SANDIA REPORT

SAND93—1754 • UC—212
Unlimited Release
Printed August 1993

Specific Systems Studies of Battery Energy Storage for Electric Utilities

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Prepared by
Sandia National Laboratories
Albuquerque, New Mexico 87185 and Livermore, California 94550
for the United States Department of Energy
under Contract DE-AC04-76DP00789

2900Q(8-81)

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SAND93-1754
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Distribution
Category UC-212

Specific Systems Studies of Battery Energy Storage for Electric Utilities

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Abstract

Sandia National Laboratories, New Mexico, conducts the Utility Battery Storage Systems Program, which is sponsored by the U.S. Department of Energy's Office of Energy Management. As a part of this program, four utility-specific systems studies were conducted to identify potential battery energy storage applications within each utility network and estimate the related benefits. This report contains the results of these systems studies.

Acknowledgments

The bulk of this report is extracted from reports provided under contract to Sandia National Laboratories by the following:

Salim J. Jabbour, Decision Focus, Inc.

Anders R. Gjerde, Decision Focus, Inc.

Stephen M. Haas, Decision Focus, Inc.

H. K. Clark, Power Technologies, Inc.

John Doudna, Power Technologies, Inc.

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Background

The Utility Battery Storage Systems Program (UBS) of the U.S. Department of Energy (DOE), Office of Energy Management (OEM), is conducted by Sandia National Laboratories (SNL). UBS is responsible for the engineering development of integrated battery systems for use in utility-energy-storage (UES) and other stationary applications. Development is accomplished primarily through cost-shared contracts with industrial organizations. An important part of the development process is the identification, analysis, and characterization of attractive UES applications.

The results of the Utility Systems Analyses element of the UBS Program are used to identify utility-based applications for which battery storage can effectively solve existing problems. The results will also specify the engineering requirements for widespread applications and motivate and define needed field evaluations of full-size battery systems.

For several years, battery energy storage has predominantly been considered a load-leveling and peak-shaving resource, and its potential for use in other utility applications has been largely overlooked. The fast-response capability of battery energy storage systems combined with other characteristics, such as modularity and ease of siting, makes this technology eminently suitable for providing support to the entire utility network for several applications such as spinning reserve, frequency control, and deferral of transmission and distribution facilities. Until now, the benefits and economic value of battery energy storage only for load-leveling and/or peak-shaving have been well understood. But the application of battery storage and the methodology to evaluate its benefits in the other, non-load-leveling applications has not been as well documented. The Electric Power Research Institute (EPRI) estimated a range of benefits for these applications from general utility information. More specific benefit information derived from utility planning scenarios and operating conditions is necessary to demonstrate the feasibility of this technology for a wide range of utility applications. The widespread application of this technology by the utility industry is predicated on the availability of this information base.

Thus, the objective of the SNL effort was to undertake a set of studies that would identify numerous applications for batteries and estimate their value in the utility network. There were two possible approaches that could be adopted for performing studies to achieve these objectives:

- examine the needs of utilities on a regional basis to identify all possible applications in which battery energy storage can play a role and estimate the value

or

- examine specific utility networks and identify potential battery energy storage applications within each network and estimate the related benefits.

The results from each approach would have different meanings and would be interpreted accordingly. A study performed on the basis of the first approach would yield estimates of the value of battery energy storage at the regional level, based not on the requirements of a particular utility, but on collective, regional conditions derived from general assumptions.

The second approach would be more focused, and identify real applications and estimate the value of the battery system based on utility-specific conditions and assumptions. The results of a study based on this approach would be immediately applicable to the host utility, while preserving the possibility that they are also applicable to other utilities with similar operating conditions. The results obtained from the second approach were deemed to be more valuable for the DOE/SNL UBS program and the utility community as a whole, and it was decided to structure the systems studies along those lines.

Utility Selection and Study Guidelines

Utilities with a diverse ownership structure and operating conditions were selected to gain insight into their processes for evaluating and implementing technology options such as battery energy storage. The utilities that were finally selected included:

- Investor-owned utility - San Diego Gas & Electric (SDG&E)
- Rural electric cooperative - Oglethorpe Power Corporation (OPC)
- Municipal electric association - Chugach Electric Association (CEA)
- Public power administration - Bonneville Power Administration (BPA)

Figure 1 shows the utility locations.

Each of the four utilities either had an active interest in battery energy storage or had a strong potential for benefiting from its use. Cost-sharing was required from

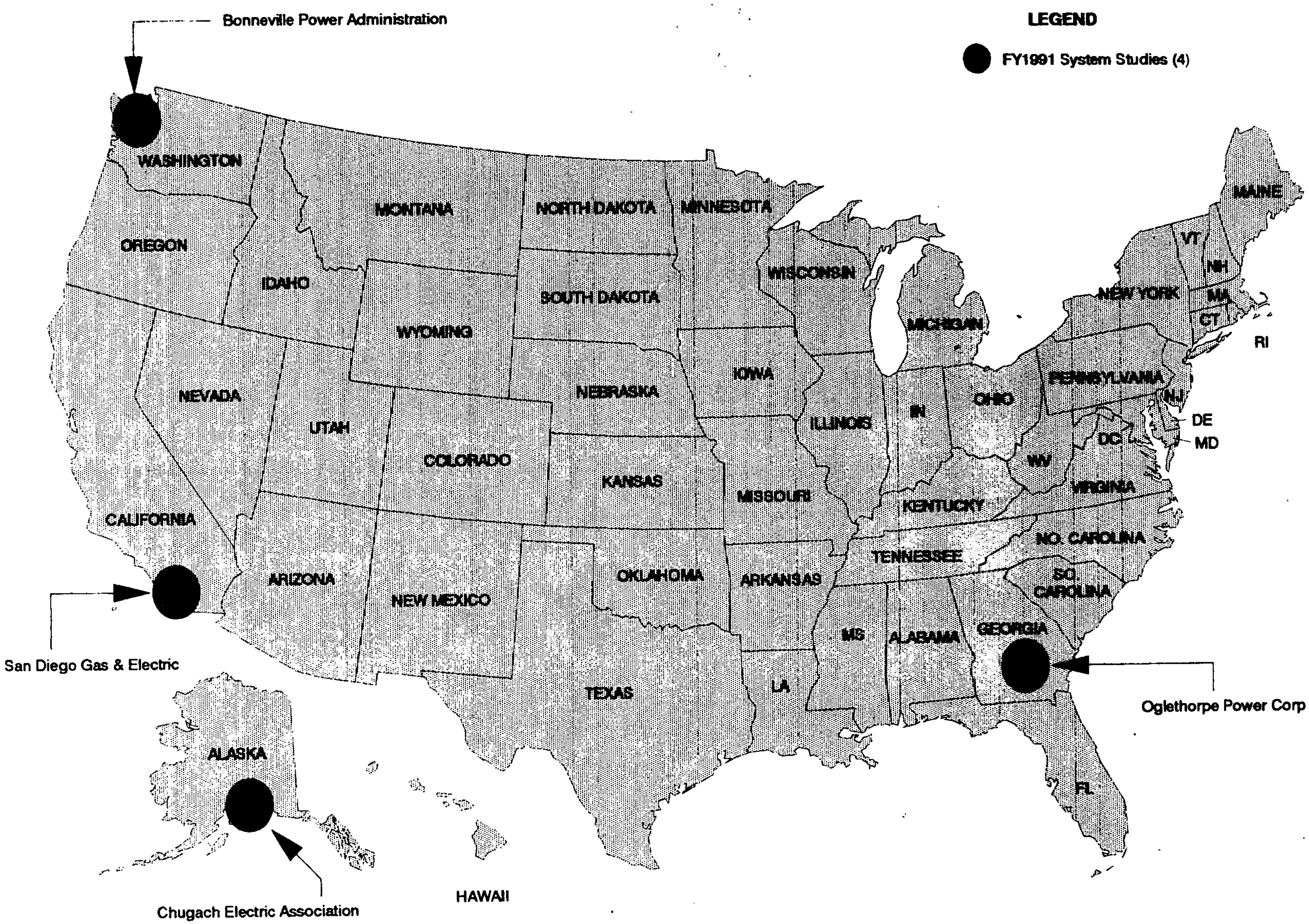

Figure 1. Geographic Distribution of Utility Systems Studies.

all utilities except BPA. SNL's share of the cost for each study and an approximate cost share from the utilities is shown in Table 1. This table also shows the start dates of each study. The studies were conducted by utility industry contractors who specialize in serving the utilities involved in the study.

The study period was initially limited to no more than 3 mo. It was felt that a longer duration could lead to a lengthy, iterative refinement process with ever-changing input assumptions and planning scenarios in an attempt to obtain better and more accurate results, whereas the 3-mo time limit established a firm deadline and forced the use of only one set of assumptions and deferred refinement of results to future studies. In practice, the studies extended beyond this planned 3-mo duration. This delay was not caused by the length of time required for the analysis, but by delays in obtaining input information and feedback from utilities as the studies progressed.

The findings of each study are summarized in the following subsections. More complete reports for three of the four utilities form the appendices of this document.

Chugach Electric Association

Decision Focus, Inc. – S. J. Jabbour

This section describes the results of a screening study to determine the benefits of adding megawatt-scale battery energy storage to the CEA system. Generation, transmission, and distribution benefits of storage, with a primary focus on benefits that are typically difficult to quantify, are addressed. The potential benefits to the costs of adding battery storage are also compared.

The CEA analysis was primarily performed by Decision Focus, Inc., with support from Power Technologies, Inc., in the areas of transmission and distribution benefits.

Findings

Generation Benefits

Generation benefits were calculated for six representative days in each of 1994, 1996, and 2000. Projected system operation was based on MAINPLAN (utility system computer simulation) runs. The benefits were calculated for five gas-fired combustion turbine units whose operation is most likely to be affected by the addition of batteries to the system. The focus was on using batteries to provide spinning reserve.

Load-Leveling

Because the marginal units on the CEA system are typically gas-fired combustion turbines for all hours, the system marginal energy costs do not differ much between on-peak and off-peak hours. Coupled with the assumed battery efficiency of around 80%, this means that no load-leveling savings could be achieved on the CEA system.

Dynamic Operating

For each of the 18 days, the potential reductions in load-following, minimum-loading, and start-up costs were calculated for each of the five generation units; reductions in these costs are achievable even though the battery is used only to provide spinning reserve. The most cost-effective unit for decommitment was identified on each day. A value of \$40 to \$70/kW-yr of battery capacity, levelized in current dollars, appears appropriate for dynamic operating benefits; this estimate was derived by calculating change from the MAINPLAN results that would be made possible by the addition of battery capacity. Of this total, more than two-thirds is from reduced minimum-loading costs, and the remainder is from reduced load-following costs.

Table 1. Utility-Specific Systems Studies

Utility	Sandia Contract	Utility Cost Share	Start Date	End Date
San Diego Gas & Electric	$46K	Yes	8/91	12/92
Oglethorpe Power Corp.	$47K	Yes	7/91	11/91
Chugach Electric (Alaska)	$43K	Yes	9/91	1/92
Bonneville Power Administration	$70K	No	2/91	11/91

Addition of battery storage to the CEA system would be effective in reducing load shedding. The amount of the reduction would depend on the size of the battery. An approximate calculation indicates that the value of the reduced load shedding could be $8 to $16/kW of battery capacity per year.

Transmission and Distribution Benefits

Current CEA transmission and distribution (T&D) facility expansion plans were reviewed to identify T&D investments that might be avoided or deferred as a result of adding battery storage to the CEA system. Several such investments were identified. The most attractive opportunities are at the Huffman, Hillside, and Girdwood substations and at the village of Hope. Based on a qualitative review of these investments and comparison with more detailed analyses for other utilities, potential T&D benefits of $20 to $200/kW of battery capacity appear reasonable. This is equivalent to a T&D benefit of $3 to $27/kW of battery capacity per year.

Cost/Benefit Analysis

Table 2 summarizes the findings. Summing the capacity (value of displacing other capacity additions), generation, reduced load shedding, and T&D benefits yields levelized current-dollar savings of $81 to $183/kW-yr, compared to a levelized current-dollar cost of $50 to $60/kW-yr. Note: For the purposes of this study, the cost estimates used are from EPRI's Technical Assessment Guide (TAG, 1989). The total cost is $703/kW for a 3-hr battery, including land cost. Reducing the storage component in the TAG cost estimates for a 3-hr battery by two-thirds yields an estimated cost of $350/kW for a 1-hr battery. With a levelized fixed charge rate of 13.7%, this is equivalent to $50 to $60/kW-yr. Thus, the analysis indicates that batteries would be a cost-effective addition to the CEA system.

Some benefits may be mutually exclusive. The interactions between the various benefits, that is, whether they are additive or mutually exclusive, depends on storage size, location, system load profiles, and load profiles at individual substations and on individual T&D lines, how the system (including the battery) is operated, and on any equipment deferred as a result of adding batteries.

Recommendations

Based on the results of this screening-level study, it is recommended that CEA consider the addition of battery storage to its system. This screening study focused only on the benefits of battery storage and it was not intended to calculate the cost of the battery system that would provide these potential benefits. A follow-on feasibility study that would provide a preliminary cost estimate of the battery system and include a detailed study to verify and refine the findings of this initial screening study by calculating the benefits more precisely is recommended. Such a study should include the following aspects:

- T&D expansion studies should be carried out, with and without batteries. Potential sites for installing batteries should be identified. Interactions among the various benefits should be considered to ensure that batteries are not being justified on the basis of benefits that may be mutually exclusive.
- More detailed calculation of generation-dynamic operating costs and benefits should be carried out, including examination of multiple weeks of system operation during each of a

Table 2. Benefits Summary for CEA System

Category	Annual Benefit ($/kW-yr)
• Capacity	30-70
• Generation Dynamic Operating (Spinning Reserve/Unit Decommitment)	40-70
• Reduced Load-Shedding	8-16
• T&D	3-27
TOTAL	81-183

larger number of years than was considered here. Such calculation should fully account for changes in system operation as load grows and should identify all possible operation savings, not only those that arise when a unit is completely decommitted.

- Comparative evaluation of the economics of battery storage with other capacity additions under consideration by CEA should be carried out. Such detailed study would also allow a better assessment of the "optimum" battery size and the best time for adding the battery plant to the CEA system.
- Identify a preferred site for locating the battery based on the findings above. Based on these findings, develop the conceptual design of the battery system and estimate its cost. Perform a cost/benefit evaluation based on the total benefits and battery system cost.

These recommendations were provided to CEA at the conclusion of this study.

San Diego Gas and Electric

Decision Focus, Inc. – S. J. Jabbour

This section describes the results of a screening study to determine the benefits of adding megawatt-scale battery storage to the SDG&E system. Generation, transmission, and distribution benefits of storage, with a primary focus on benefits that are typically difficult to quantify, are addressed. The potential benefits to the costs of adding battery storage are also compared.

The SDG&E analysis was primarily performed by Decision Focus, Inc., with support from Power Technologies, Inc., in the areas of transmission and distribution benefits.

Findings

Generation Benefits

Generation benefits were calculated for eight days during 1990 and 1991, one weekday and one weekend day for each season, using actual SDG&E data. The benefits were calculated for five gas-fired steam turbine units whose operation is most likely to be affected by the addition of batteries to the system. Two modes of battery operation were considered: daily charge/discharge with a 3-hr battery, and provision of spinning reserve only with a 1-hr battery. The spinning reserve mode appears to be more cost-effective.

Load-Leveling

Because the marginal units on the SDG&E system are typically gas-fired steam turbines for all hours, the system marginal energy costs do not differ much between on-peak and off-peak hours. With the assumed battery efficiency of 80%, this means that no load-leveling savings could be achieved on the SDG&E system.

Dynamic Operating

For each of the eight days, the potential reduction in load following, minimum loading, start-up, and spinning reserve costs was calculated for each of the five units. The most cost-effective unit for decommitment was identified on each day. For the 1990-1991 period, the savings were about \$23 to \$26/kW-yr of battery capacity; the biggest component of the savings is from reductions in load-following costs. That is, each kilowatt of battery capacity would reduce annual system operating costs \$23 to \$26. Accounting for inflation and increases in natural gas prices, this is equivalent to an annual savings of about \$50, levelized in current dollars, per kW/yr. The savings are likely to increase in the future as load growth forces increasing utilization of less economic units.

Environmental

Storage in general, and batteries in particular, has the potential to shift the type and location of emissions of NO_x, SO_x, and CO_2; NO_x is of greatest concern in Southern California. Even if providing only spinning reserve, batteries have the potential to reduce NO_x emissions by allowing the system to be operated more efficiently. The addition of batteries to the system might also make it unnecessary to retrofit expensive pollution controls to an existing gas-fired unit, if that unit's operation would be sharply reduced as a result of adding batteries. These benefits could be worth up to about \$20/kW of battery capacity per year.

Transmission and Distribution Benefits

This project identified the potential role battery storage could play in providing equal or better performance than other T&D options, such as adding new T&D facilities and equipment. Current SDG&E T&D facility expansion study results and transmission and distribution system design practices were reviewed with SDG&E personnel to identify anticipated and potentially needed transmission additions.

The findings of this initial study indicate that strategically installing battery storage on the SDG&E system may result in large T&D system benefits up to $1,200/kW, equivalent to as much as $200/kW of battery capacity per year. The actual magnitude of the site specific T&D benefits and corresponding battery storage requirements should be determined on a case-by-case basis from more detailed analysis. Further analysis should include the development of load profiles for substations that are candidate battery sites so that the number of hours of storage required for equipment deferral can be determined.

Cost/Benefit Analysis

Table 3 summarizes the findings. Summing the capacity, generation, environmental, and T&D benefits yields levelized current-dollar savings of $100 to $370/kW-yr, compared to a levelized current-dollar cost of $60 to $130/kW-yr. These values suggest that batteries would be a cost-effective addition to the SDG&E system.

Some benefits may be mutually exclusive. The interactions between the various benefits, that is, whether they are additive or mutually exclusive, depends on storage size, location, system load shapes, and load shapes at individual substations and on individual T&D lines, how the system (including the battery) is operated, and on any equipment deferred as a result of adding batteries.

Recommendations

Based on the results of this screening-level study, it is recommended that SDG&E consider the addition of battery storage to its system. A detailed study to verify the findings of this initial screening study and to calculate the benefits more precisely is recommended. Such a study should include the following aspects:

- More detailed calculations of generation-dynamic operating costs and benefits should be carried out, including examination of multiple weeks of system operation during the course of the year and consideration of how system operation, and especially the operation of marginal units, is likely to change in the future.
- Detailed T&D expansion studies should be carried out, with and without batteries. Potential sites for installing batteries should be identified. Interactions among the various benefits should be considered to ensure that batteries are not being justified on the basis of benefits that may be mutually exclusive.
- Comparative evaluation of the economics of battery storage with other capacity additions under consideration by SDG&E should be carried out.

Such detailed study would also allow a better assessment of the "optimum" battery size and the best time for adding the battery plant to the SDG&E system.

Oglethorpe Power Corporation

Power Technologies, Inc. – H. K. Clark

The methodology for the OPC study consisted of evaluating and quantifying the reasonable benefits attainable from the battery storage application and comparing the total benefits against the cost of the battery storage system. Several benefits and the particular characteristics of the OPC system were reviewed and analyzed including:

- Load profile with and without direct load control,
- Future generation expansion plan,

Table 3. Benefits Summary for SDG&E System

Category	Annual Benefit ($/kW-yr)
• Capacity	40-75
• Generation	
Load-Leveling	0
Dynamic Operating	50-75
• T&D	10-200
• Environmental	1-20
TOTAL	101-370

- Role of pumped hydro storage and its impact on load leveling,
- Cost of purchased power and energy,
- Future transmission projects,
- Future distribution projects,
- Radial transmission lines/substations,
- Need for backup power source.

Five specific substation locations within the OPC system for battery storage to defer T&D projects were selected for this study: Habersham (H), Egypt (E), Satilla (S), Vidalia (V), Warrenton (W). The battery sizes used for these five locations are shown in Table 4.

The results of a benefit-to-cost comparison are presented in Figure 2. The methodology used for benefit-to-cost comparison is essentially based on calculating the present worth of all the annual cost savings/ benefits accruing due to the battery and the annual cost of owning and operating the corresponding battery plant.

Only four major benefits due to battery storage are included in these benefits-to-cost ratios. They are:

- Generation capacity,
- Transmission deferment,
- Distribution deferment,
- Value of service or cost of outage.

The battery storage application identified in this study is mostly in the form of a backup or reserve source. It is not used in the general sense of load leveling. A generation capacity (kW) credit based on a 10-hr discharge rating is applicable. This battery kW (based on 10-hr discharge rating) is essentially a generation reserve source. A 10-hr discharge rating is used so that even if this reserve is called upon during the annual peak load condition, the battery will be able to provide the power (kW) equal to the credit it has received for the longest peak load period of 10 hr. Thus, for example, a 10-MW, 1-hr battery is given a credit of 1 MW. The cost of the battery credit is based on the least expensive generation alternative, which is a combustion turbine. The annual cost savings from avoiding the investment in this generation is credited to the battery.

The transmission credit is computed on the basis of the cost of deferring T&D projects. The actual capital

Table 4. Selected Battery Sizes

	OPC Substation Locations (designated by letter code)				
	H	E	S	V	W
MWh	7.5	26.0	9.0	217.0	218.0
MW	1.5	6.5	1.5	31.0	43.6
hr	5	4	6	7	5

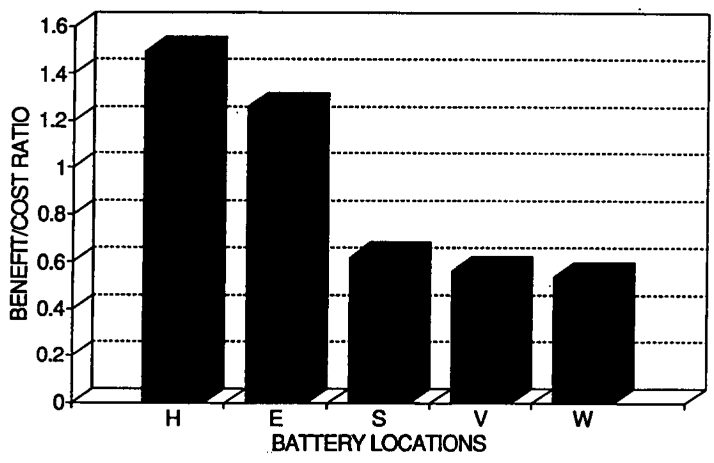

Figure 2. Comparison of Benefits to Cost for Five Battery Locations.

cost expenditure is considered to be postponed by a number of years. The annual cost savings due to the postponement is credited to the battery benefits. The distribution benefits are also calculated similarly.

The fourth and last benefit computed in this study is the value of service or cost of outages. The interruption cost, or value of service (VOS) data, is considered to be suitable to relate the worth of service reliability to the cost of service. The VOS or outage costs depend upon type of load, frequency and duration of interruption, and timing of the interruption. However, some of these costs have a wide range. The cost range for 1-hr interruption has been reported in the literature.

The actual cost or VOS used in this study is shown in Table 5. For each of the five types of battery applications analyzed in this study, it is assumed that the total amount of energy not served or kWh interrupted per year is equal to the total battery kWh rating. This means that, on the average, the sum of energy supplied to the customers by the battery during the interruptions over a period of 1 yr is equal to its total energy rating.

After computing benefits, the battery storage system costs were calculated. For the battery alone, a different life is used than for the entire battery storage plant. The operating and maintenance (O&M) cost used is 0.25% of the capital cost. Amortizing the capital cost is levelized over the plant life. The salvage value of the battery is included in computing the levelized annual cost. The replacement cost of battery cells is included as needed. The converter and balance of plant (BOP) are assumed to have a 30-yr life and no salvage value.

The benefit-to-cost ratio for batteries application at five different locations for T&D deferment was computed. The percentage benefit of the four applications is shown in Figure 3.

- Backup source (considering cost of outage, VOS, or value of unserved energy) credit was the most significant benefit from battery storage. In terms of customer loads on the OPC/electric membership corporation (EMC) system, the poultry industry loads are considered to suffer high damage when service interruption occurs. Hence, some of these egg hatcheries and chicken farms currently provide, or plan to install, backup diesel generation. Application of a 7,500-kWh, 5-hr discharge rating battery at Hollywood substation showed a

Table 5. VOS or Outage Cost for 1-hr Interruption

	$/kWh Not Served	
	Low	High
Residential	0.05	5.00
Industrial	2.00	53.00
Commercial	2.00	35.00
Poultry and Eggs	0.12	5.68

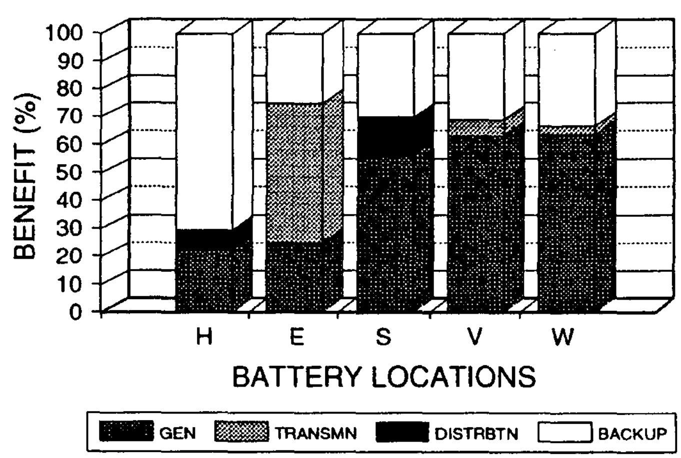

Figure 3. Percent of Benefits for Five Battery Locations.

benefit-to-cost ratio of 1.5. This was one of the highest benefit-to-cost ratios obtained in this study.

- Whenever there is an outage on a radial line, an interruption of service occurs. If the line is inaccessible or has difficult terrain, repair of the line may be difficult and the corresponding outage may be lengthy. One such example selected for this study was application of a battery for backup instead of building a second transmission line. The benefit-to-cost ratio is 1.26 for this case. This substation is an attractive location (out of the five analyzed) for the battery and deferment of a second transmission line.
- A third substation was selected for evaluating the deferment of a new distribution transformer. The benefit-to-cost ratio turned out to be 0.62. The generation capacity credit was the largest, followed by the backup source credit, with distribution credit being the least. No transmission deferment was used in this example. A higher backup source credit in lieu of a new transmission line credit may be warranted here. The VOS has to be $8.00/kWh for break-even of benefit-to-cost ratio as compared to $2.61/kWh (used in the base case for the ratio of 0.62).
- Deferment of an additional 140-MVA, 220/115-kV transformer at two substations was evaluated. The benefit-to-cost ratios were 0.57 and 0.54, respectively. Because of parallel 230-kV and 115-kV lines contained by these substations, oversize battery storage capacity was needed to provide a given load reduction on the existing transformers. Hence, the battery and its cost would be about twice that required to reduce load on a radially connected transformer, in which case the benefit-to-cost would be nearly break-even.

In addition to base cases, several sensitivity analyses were performed for the highest benefit-to-cost application. The sensitivity analysis included changing the following parameters, one at a time:

- Battery cost,
- Converter and BOP cost,
- Battery life,
- Salvage value,
- Value of service/cost of outages,
- Extended distribution benefits.

In the first case, the battery's cost can be 60% higher than the base case for the value of benefits to equal the cost of battery storage. In the second case, the PCS and BOP cost was doubled, and this reduced the balance-to-cost ratio from 1.49 to 1.27. These two sensitivity cases show that the battery cost has a higher effect on the overall cost as compared to the converter and other costs.

In the third case, the battery life was reduced to 10 yr from 15 yr. This means two battery replacements are included in this case as compared to only one battery replacement in the base case. The benefit-to-cost ratio decreased from 1.49 to 1.42, which is not a substantial reduction. Thus, there may be economic advantages in improving the cycle life of lead-acid batteries, but the chronological life is not significant as compared to the battery cost itself.

In the fourth case, the salvage value was doubled from 20%. Surprisingly, the benefit-to-cost ratio increased to 1.68. This may be partly explained by the escalation used in computing replacement battery cost. Essentially, the salvage part of the battery cost is escalated by 4.5% because at the end of battery life, the trade-in value of the battery is assumed to be equal to the salvage percentage of the new battery cost.

The fifth sensitivity case involved the value of service or backup source credit. As noted earlier, this item contributed most to the battery benefits. This VOS may be about 50% of the base case for the break-even cost.

In the sixth sensitivity case, the distribution benefits were extended to 30 yr. The base case showed the distribution transformer deferment for 10 yr only. Because the battery can be moved to another location, similar distribution benefits may continue to acrue. This case shows an increased benefit-to-cost ratio of 1.58. The cost of moving the battery and any change in value of service are not recognized in this case.

Recommendations

Battery energy storage at substations with radial feeds and/or serving critical customer loads may have positive benefits for OPC. OPC has approximately 24 such sites that could be candidates for further, more detailed analysis to determine the benefits of battery energy storage at these sites. A follow-on feasibility study that includes the conceptual design of site-specific battery system(s) and further refines the value of the benefits at each site was recommended to OPC.

Bonneville Power Administration Puget Sound Area

Power Technologies, Inc. – H. K. Clark

In 1989, planning studies at BPA revealed that major additions to the existing transmission system across the Cascade Range might be required in the mid-nineties. The studies indicated that 1,600 MW of expected growth in the Puget Sound area peak load between 1993 and 2003 would result in voltage stability problems on the highly stressed 500-kV system across the Cascades.

BPA engineers identified 10 possible solutions to the problems. These included a new double-circuit 500-kV line across the Cascades, and up to 600 MW of combustion turbine (CT) capacity in the Puget Sound area. Some partial solutions included water heater fuel switching, time-of-use rates, water heater controls, low-flow shower heads, conservation, curtailment, and voltage support equipment.

SNL initiated this battery application study to determine if battery energy storage could compete with the options being considered by BPA, especially if it could defer a 500-kV transmission line or displace CT capacity.

Combustion Turbine Displacement

The daily winter load profile in the Northwest helps make battery energy storage attractive. The load profile from two days of particular concern to BPA are shown in Figure 4. The February 3, 1989, peak is the more difficult one for a battery because it is relatively flat. However, even on this day, the peak could be reduced 200 MW by a battery with just 1.35 hr of storage. A 400-MW peak reduction would require 2.2 hr of storage.

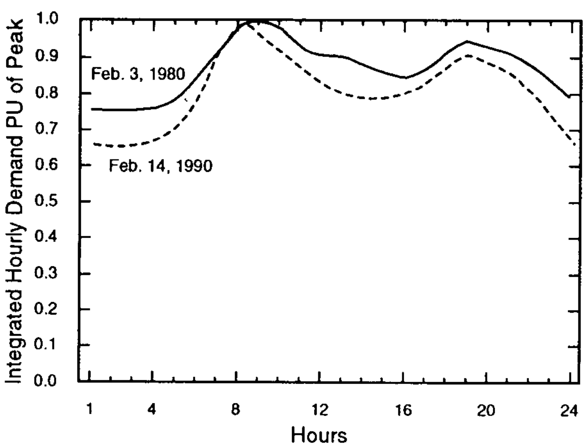

Figure 4. Load Shapes for High-Load Days of Concern to BPA.

One of the problems with the use of CTs to address the Puget Sound voltage problem is that they cannot be started quickly enough to prevent voltage instability following loss of a major 500-kV line. Hence, they must be running when load is high. This adds significantly to the cost of the CT option. Batteries can be switched on and brought to full power in seconds.

A benefit of CTs is that they "firm up" BPA energy commitments. That is, they allow BPA to commit to firm energy deliveries that can be served largely from hydro plants. Should water shortages occur, the CTs can be used to meet those obligations.

Based on recent SNL estimates of battery and converter costs and the instant on-off capability of batteries, batteries could provide the needed peak shaving at less cost than CTs. However, batteries cannot firm up hydro energy sales as can CTs, and thus cannot compete with this significant CT benefit.

Cross-Cascades 500-kV Line Deferral

The 500-kV line across the Cascades was the second target of the battery application study. However, continuing BPA studies revealed an opportunity to substantially boost the capacity of the existing 500-kV system by adding one 500-kV substation, a 20-mile section of 500-kV line, several large shunt capacitor banks, and two static var compensators. These additions, combined with conservation and load management, have deferred the need for combustion turbines and the new cross-Cascades 500-kV line indefinitely. Further, the cost of these options is less than 30% of the cost of the line. Further study of this option and its cost was deferred because BPA had already commited to the construction of this project.

Local Benefits of Battery Energy Storage

Batteries need not be located in high-voltage substations to provide transmission benefits. Battery energy storage can be more attractive if it is divided into small units and placed close to customer loads to reap further benefits. The potential for this in the Northwest was assessed through discussions with utilities served by BPA in the Puget Sound area. Interesting applications in which batteries might relieve the cross-Cascades transmission problem and provide local benefits are as follows:

- Boeing Wind Tunnel - At the time of the study Boeing was planning a 300-MW wind tunnel in the Puget Sound area. The facility would require power rising at 150 MW/min during start-up and decaying at 150 MW/min during shutdown. However, utilities in the Northwest limit customer load variations to 50-MW/min. A battery could be discharged during wind tunnel start-up and charged during shutdown as shown in Figure 5 to reduce load changes to 50-MW/min. A 5-min battery would suffice, though cell life may dictate a somewhat larger battery. The converter rating would be about 125 MW.

- Aluminum Plants - BPA serves two aluminum plants through the Seattle City Light (SCL) system. Batteries at the aluminum plants could reduce the risk of very costly aluminum cell freeze-up during power outages. A 30-min battery would prevent freeze-up. The MW level necessary to prevent freeze-up was not determined.
- Distribution Feeder Thermal Limits - SCL designs 26-kV feeders for a 600-A maximum capacity (27 MW) and routes them to carry 300 A during winter cold snaps. Each feeder can thus provide backup to one other feeder. However, in one area, feeders and their associated substation are reaching full capacity, and the load continues to grow. One battery, centrally located, could serve a number of feeders. The necessary battery MW rating and storage time were not determined (depends on load profile).
- Fuel Cells - SCL is looking at fuel cells as a possible long-term solution to the increasing load density in the city. Because fuel cells are dc devices, they might share a power converter with a battery. This would reduce battery energy storage cost, and allow energy from the fuel cell to be stored at night when the system load is low.

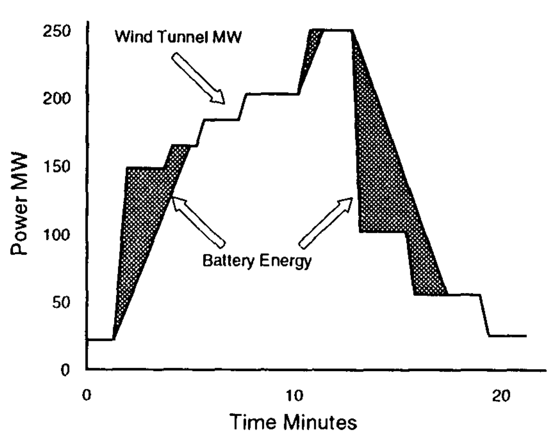

Figure 5. Typical Wind Tunnel Load Profile and Battery Energy Required to Limit Load Changes to 50 MW/min.

- Big Six Customers - Some of SCL's large customers have highly variable loads and thus are subject to demand charges to cover the extra generation and transmission equipment associated with such loads. Batteries could smooth out this load. Sizes were not determined.
- Tacoma Public Utilities - Load is largely commercial and residential; however, an industrial pocket in the tide flats includes Occidental Petroleum (90 MW), Penwalt (60 MW), and others. As much as 400 MW of cogeneration may be developed in the tide flats area, along with 250 MW in the Fredrichsen area. Voltage regulation is an increasing problem in the area, but may be solved by cogeneration. Batteries may provide reliability, load smoothing, and voltage regulation benefits in this area.
- Whidbey Island - The island load is largely residential and is growing. It is fed by two 115-kV lines at the north tip. The 115-kV lines are long and subject to occasional failure. A 28-MW diesel-driven generator is run to regulate voltage when one line is out and supply some of the island load when both lines are out. Rotating blackouts are used to share the diesel among all customers. The diesel cannot be fully loaded because of feeder "cold load pickup." A 230-kV line extending onto Whidbey Island will help after 1995, but reliability will still be low by Puget Power standards. The best solution, a cable tie between Whidbey Island and the Seattle area, would cost about $10 million. A battery could supply the 10- to 20-min "cold load" portion of the last feeders to be picked up, thus increasing the load the diesel can serve. It could then smooth the load to further increase diesel loading. A 5- to 10-MW 1-hr battery would be needed.
- Power Plant Black Start - Puget Power has some power plants that could be restarted more rapidly after a blackout if a nearby source of power were available.

Generation Benefits of Battery Energy Storage in the Northwest

Discussions were also held with BPA and Puget Sound area utilities to identify generation benefits of battery energy storage. All of the utilities have hydro plants that provide highly flexible scheduling to maximize economy and impose few generation constraints on operation.

Conclusions

There are limited opportunities at present for battery energy storage plants to capture large benefits in the Puget Sound area by deferring major transmission and CT investment because less costly alternatives have been identified. Also, the usual generation benefits of energy storage are not available in the Northwest.

Battery energy storage may, however, still have a place in the study area at the subtransmission and distribution level. It could be attractive by providing distribution system benefits and displacing some of the more costly alternatives that will be used to defer major transmission and CT investment.

Battery energy storage may also provide a hedge against failure of some of the less well-proven alternatives to major transmission and CT investment. For instance, if conservation, fuel switching, or load management do not limit peak load growth as expected, batteries could be installed quickly and on short notice to serve peak load.

Evaluating the cost-effectiveness of battery energy storage in an environment where there are no large benefits is difficult. It requires careful scrutiny of the many possible beneifts that can be derived from battery attributes (see Table 6). This, in turn, requires close cooperation of all persons or organizations that may recognize a benefit from the installation. In the Puget Sound area, this would include at least several departments within BPA, several from one of BPA's client utilities, and, perhaps, one or more from an industrial customer.

Table 6. Battery Attributes

No-Cost Start/Stop
Fast Response (kW and kvar)
Four-Quadrant Operation (simultaneous kW and kvar)
Unmanned (Remote Control)
High Reliability/Availability
Low Maintenance
Short Lead-Time Installation
Low Environmental Impact (Siting Flexibility)
Limited Space Requirement (Siting Flexibility)

Appendix A

Potential Benefits of Battery Storage to Chugach Electric

POTENTIAL BENEFITS OF BATTERY STORAGE TO CHUGACH ELECTRIC
—A Screening Study—

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and

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April 1992

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EXECUTIVE SUMMARY

This report describes the results of a screening study to determine the benefits of adding megawatt-scale battery energy storage to the Chugach Electric Association (CEA) system. The report addresses generation, transmission, and distribution benefits of storage, with a primary focus on benefits that are typically difficult to quantify. The report also compares the potential benefits to the costs of adding battery storage.

BENEFITS OF BATTERY ENERGY STORAGE

The addition of a storage unit to a utility system can provide a wide range of benefits that depend on the characteristics of the individual utility, the manner in which the storage unit is operated, and its siting within the utility network as well. Generation load-leveling has long been advocated as the primary reason for adding storage to a utility's generating mix. The most obvious benefit and the easiest to quantify, load-leveling results in the replacement of expensive peak power with cheaper power from base-load plants, increasing the capacity factor of the base-load plants during off-peak periods to displace the use of premium oil/gas fuels during on-peak periods. In the past several years, generation dynamic operating benefits (DOBs) have also been recognized as significant benefits of storage plants. The types of benefits include those accruing from the provision of spinning reserve, reduced minimum loading, and fast response rates. These benefits are overlooked in conventional methods. Another commonly recognized benefit from storage in general, and batteries in particular, is reduction in transmission and distribution (T&D) costs. T&D benefits are due in part to the siting flexibility and in part to the rapid response times for batteries. T&D benefits include deferral of T&D investment, reduced losses, and voltage regulation, as well as others.

CEA FINDINGS

Generation Benefits

Generation benefits were calculated for six representative days in each of 1994, 1996, and 2000. Projected system operation was based on MAINPLAN runs. The benefits were calculated for five gas-fired combustion turbine units whose operation is most likely to be affected by the addition of batteries to the system. The focus was on using batteries to provide spinning reserve.

Load-Leveling. Because the marginal units on the CEA system are typically gas-fired combustion turbines for all hours (usually the Beluga and Bernice Lake units), the system marginal energy costs do not differ much between on-peak and off-peak hours. Coupled with the assumed battery efficiency of around 80 percent, this means that no load-leveling savings could be achieved on the CEA system.

Dynamic Operating. For each of the 18 days the potential reduction in load following, minimum loading, and startup costs was calculated for each of the five units; reductions in these costs are achievable even though the battery is used only to provide spinning reserve. The most cost-effective unit for decommitment was identified on each day. A value of $40 to $70 per kW-year of battery capacity, levelized in current dollars, appears appropriate for dynamic operating benefits. Of this total, more than two-thirds is from reduced minimum loading costs, and the remainder is from reduced load following costs..

Reduced Load Shedding

Addition of battery storage to the CEA system would be effective in reducing load shedding. The amount of the reduction would depend on the size of the battery. A very approximate calculation indicates that the value of the reduced load shedding could be $8 to $16 per kW of battery capacity per year.

Transmission and Distribution Benefits

Current CEA transmission and distribution facility expansion plans were reviewed to identify T&D investments that might be avoided or deferred as a result of adding battery storage to the CEA system. Several such investments were identified. Based on a qualitative review of these investments and comparison with more detailed analyses for other utilities, potential T&D benefits of $20 to $200 per kW of battery capacity appear reasonable. This is equivalent to a T&D benefit of $3 to $27 per kW of battery capacity per year.

COST/BENEFIT ANALYSIS

Table S-1 summarizes the findings. Summing the capacity, generation, reduced load shedding, and T&D benefits yields levelized current-dollar savings of $81 to $183/kW-year, compared to a levelized current-dollar cost of $50 to $60/kW-year.[1] These values suggest that batteries would be a cost-effective addition to the CEA system.

Some benefits may be mutually exclusive. The interactions between the various benefits, i.e., whether they are additive or mutually exclusive, depends on storage size, location, system load shapes, load shapes at individual substations and on individual transmission and distribution lines, how the system (including the battery) is operated, and on any equipment deferred as a result of adding batteries.

1. For the purposes of this study, the cost estimates used are from EPRI's Technical Assessment Guide (TAG, 1989). The total cost is $703/kW for a 3-hour battery, including land cost. Reducing the storage component in the TAG cost estimates for a 3-hour battery by two thirds yields an estimated cost of $350/kW for a 1-hour battery. With a levelized fixed charge rate of 13.7 percent, this is equivalent to $50 to $60/kW-year for a 1-hour battery. While these estimates are acceptable at this stage, actual system cost information from the Puerto Rico Electric Power Authority 20 MW battery project are discussed in the subsection of Section 1 titled "The PREPA 20 MW Battery Project."

Table S-1
BENEFITS SUMMARY FOR CEA SYSTEM

Category	Annual Benefit ($/kW-year)
Capacity	30-70
Generation	
Load Leveling	0
Dynamic Operating	40-70
Reduced Load Shedding	8-16
T&D	3-27
TOTAL	81-183

RECOMMENDATIONS

Based on the results of this screening-level study, it is recommended that CEA seriously consider the addition of battery storage to its system. A detailed study to verify the findings of this initial screening study and to calculate the benefits more precisely is recommended. Such a study should include the following aspects:

1. More detailed calculation of generation dynamic operating costs and benefits should be carried out, including examination of multiple weeks of system operation during each of a larger number of years than was considered here. Such calculation should fully account for changes in system operation as load grows, and should identify all possible operation savings, not only those that arise when a unit is completely decommitted.

2. Detailed T&D expansion studies should be carried out, with and without batteries. Potential sites for installing batteries should be identified. Interactions among the various benefits should be considered to ensure that batteries are not being justified on the basis of benefits that may be mutually exclusive.

3. Comparative evaluation of the economics of battery storage with other capacity additions under consideration by CEA should be carried out. Such detailed study would also allow a better assessment of the "optimum" battery size and the best time for adding the battery plant to the CEA system.

1

INTRODUCTION

This report describes the results of a screening study to determine the benefits of adding megawatt-scale battery energy storage to the Chugach Electric Association (CEA) system. The report addresses generation, transmission, and distribution benefits of battery energy storage, with a primary focus on benefits that are typically difficult to quantify. The potential benefits are compared to the costs of adding battery storage to determine the cost-effectiveness of adding battery energy storage to the CEA system.

BENEFITS OF BATTERY ENERGY STORAGE

The addition of battery energy storage to a utility system can provide a wide range of benefits that depend on the characteristics of the individual utility, the manner in which the battery storage unit is operated, and its siting within the utility network as well. Generation load-leveling has long been advocated as the primary reason for adding storage to a utility's generating mix. The most obvious benefit and the easiest to quantify, load-leveling results in the replacement of expensive peak power with cheaper power from base-load plants, increasing the capacity factor of the base-load plants during off-peak periods to displace the use of premium oil/gas fuels during on-peak periods.

In the past several years, generation dynamic operating benefits (DOBs) have also been recognized as significant benefits of battery energy storage plants. The types of benefits include those accruing from the provision of spinning reserve, reduced minimum loading, and fast response rates. An EPRI report[1] provides compelling evidence on the importance of dynamic operating considerations. The three major conclusions of the EPRI report are as follows:

- A large portion of the operating costs of cycling power plants results from fluctuating electric loads. These costs are called *dynamic operating costs.*

- Technologies that offer operating flexibility at minimal costs (e.g., energy storage power plants) provide power systems with significant operating cost savings. These savings are called *dynamic operating benefits.*

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1. *Dynamic Operating Benefits of Energy Storage,* EPRI AP-4875.

- A large fraction (up to two-thirds) of the savings provided by technologies with significant operating flexibility are overlooked in conventional methods.

Another commonly recognized benefit from storage in general, and batteries in particular, is reduction in transmission and distribution (T&D) costs. T&D benefits are due in part to the siting flexibility and in part to the rapid response times for batteries. T&D benefits include deferral of T&D investment, reduced losses, and voltage regulation, as well as others.[2]

Another category of benefits is what might be termed strategic benefits, those that relate primarily to the changing environment in which utilities operate. This includes reduction in environmental emissions, greater ability to transact power with other utilities and with non-utility generators, and greater flexibility in general.

This study quantifies the benefits of battery storage in the first two categories—generation and T&D—for the Chugach Electric Association system. It then compares these benefits to the costs of adding lead-acid battery storage.

LEAD-ACID BATTERY TECHNOLOGY[3]

The major elements of a lead-acid battery energy storage plant are the battery, the converter, and the balance of the plant. During charging, alternating current electricity is converted to direct current electricity by the converter and stored electrochemically by the battery. During discharge, direct current electricity is drawn from the battery and converted to alternating current electricity for use on the utility grid. Figure 1-1 is a schematic of a battery energy storage system.

Utility battery storage systems consist of commercially available lead-acid cells similar to those used in submarines or large telephone switching installations. A typical cell size is 5 to 10 kWh. Many cells are combined in a battery unit, with typical storage times of 1 to 5 hours and power capacities of 2 to 100 megawatts. For example, the 4-hour capacity lead-acid battery storage plant at Southern California Edison Company's Chino substation has a capacity of 10 MW; the battery consists of 8,256 cells, each measuring approximately 16 in. (41 cm) long, 14.5 in. (37 cm) wide, and 25 in. (65 cm) high, and weighing about 585 lb. (266 kg). The cells are supported on steel frames in groups of 6 to form 12-V modules. The battery is connected to the SCE system at 13.8 kV.

2. *Potential Economic Benefits of Battery Storage to Electrical Transmission and Distribution Systems*, EPRI GS-6687.

3. Research is under way on a number of advanced battery systems, including sodium sulfur, zinc bromine, and others. In this report, however, we focus on and use costs for the one technology that is commercially available now: lead-acid batteries.

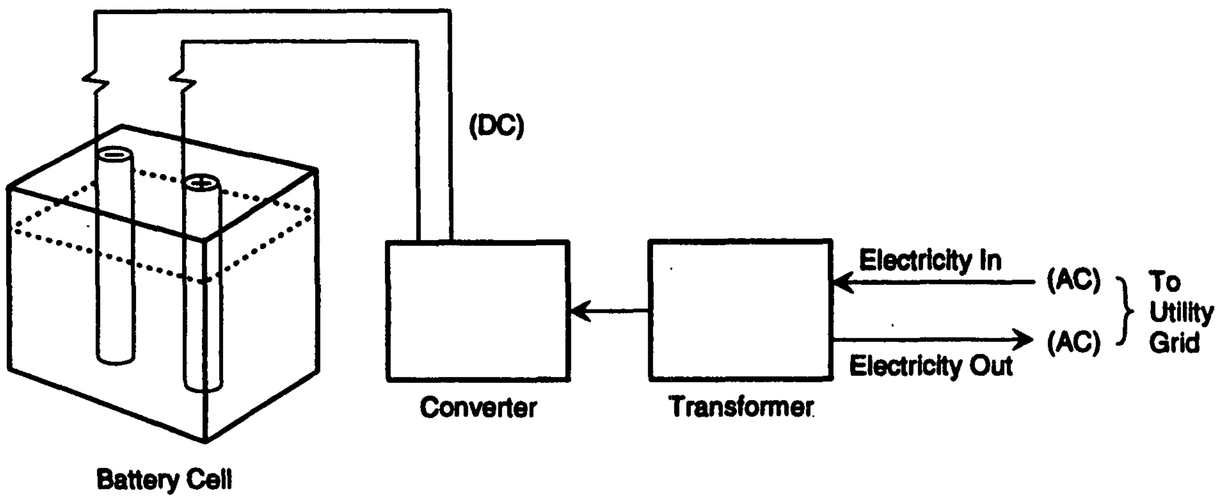


Figure 1-1. Battery Energy Storage System

The AC-DC converter consists of electronic equipment similar to that used in large uninterruptible power supply (UPS) systems, and in wind, photovoltaic, and fuel cell power generation systems. The balance of the plant consists of the structural, mechanical, electrical, control, and safety subsystems required to perform system integration and interface of the battery to the utility system.

Battery energy storage plants are truly modular and can be installed quickly, enabling them to match load growth much more easily and accurately than larger, custom-built, site-specific plants. Construction time for a lead-acid battery plant is less than one year. Batteries are compact, quiet and non-polluting, so they can be sited near population centers. They can operate efficiently over a wide range of loads, and are actually more efficient at part load than at full load. They can also respond to load changes in just 20 milliseconds.

Table 1-1 provides cost and performance data for battery storage sizes of 3 and 5 hours, installed at a 20 MW plant. These data are from the EPRI Technical Assessment Guide™.

BATTERY ATTRIBUTES

Ratings

Batteries have two key ratings. One is the power rating (kW or MW). It is the maximum power that the battery can provide for an extended period during the discharge part of its cycle. The power rating is dictated by the lowest continuous rating among the components that make up the system: the cells, the busbars, the converter, or the converter transformer. In an optimized design all components will have about the same continuous capability. However, the converter is usually the most limiting device and the one with the least margin. While cell life will be reduced somewhat when a battery is operated above its power rating, GTOs in the converter may fail at a power level as little as 10% above their rating. The converter controls are thus designed to prevent converter overloading.

Table 1-1
LEAD-ACID BATTERY COST AND PERFORMANCE DATA

	Three Hour	Five Hour
Plant Capital Cost, Dec. 1988 $/kW		
Power charging/discharging	125	125
Storage	510	727
Startup, inventory, land	16	21
Total capital requirement	651	873
Operation and Maintenance Costs, Dec. 1988 $		
Fixed, $/kW-yr	0.6	1.4
Incremental, mills/kWh	8.6	6.5
Energy Requirements (kWh Output/kWh Input)		
Full load	0.73	0.76
25% load	0.78	0.79
Average annual	0.74	0.76
Plant Construction Time, Years	1	1
Unit Life, Years	30	30

The maximum continuous charge power level is dictated by the same considerations, and is thus usually the same as the power rating. Note, however, that in practice the charge rate may be lower than the rating to increase battery life if low-cost energy is available over a period sufficient to fully charge the battery at the lower rate.

The second battery rating is its energy storage rating (kWh or MWh). The storage rating is the energy that the battery can provide to the system during a normal daily discharge. In current designs the energy rating is usually 80% of the energy the battery could provide if discharged fully. The energy rating is solely a function of the individual cell ratings and the number of cell strings in parallel. The battery energy rating can be increased by adding parallel strings of cells.

The batteries produced to date have not been given an overload rating. However, batteries, buswork, transformers, and circuit breakers will all tolerate some overload. Though a converter cannot be significantly overloaded, a converter could be oversized to take advantage of the overload capability of other components.

Cell Types

Two types of lead-acid cells are in use. The one first used in utility energy storage applications is the 'flooded' cell. It is typically 14 to 18 inches square and 24 to 30 inches tall. It has a vent on the top covered by a filter so that only hydrogen escapes from the battery. The

Southern California Edison installation uses flooded cells, as will the 20 MW battery that will be installed in Puerto Rico in 1993.

The second type is the "sealed" or "Valve Regulated" Lead Acid (VRLA) battery which is a relatively recent derivative of the traditional "flooded" cell battery. In this design the electrolyte is immobilized as a gel or absorbed in a glass mat between the positive and negative plates of the cell. This allows the battery to be sealed and removes the need for water addition during its operating life. The sealed construction offers greater flexibility in configuring the layout of a battery energy storage plant while reducing O&M costs. San Diego Gas & Electric recently purchased a 210kW/420kWh VRLA battery for a commuter trolley peak-shaving demonstration project which is expected to commence operation by mid-1992. This project will be the first use of a VRLA battery in a utility application. The selection of a VRLA battery was driven by the limited land availability at the project location. A comparable flooded cell type of battery would not have been able to meet the restrictive space requirements.

Cycle and Battery Life

The normal 'load-leveling' cycle for a battery is a diurnal one in which the battery is charged at night and discharged to follow load during the day. In most load-leveling applications, batteries are cycled only on weekdays. In spinning reserve applications there are no regular charge-discharge cycles, but the battery is discharged to replace generation lost due to an unscheduled outage. In some special applications, such as frequency regulation, multiple shallow charge-discharge cycles may occur over periods of minutes or hours.

Batteries can be cycled daily to 'shift' load from peak hours to off-peak hours. However, because battery life is reduced as the depth of discharge is increased, there is an optimum depth of discharge for each application. The optimum depth occurs where the incremental benefit of load-leveling equals the cost of incremental battery loss of life. Though the relationship of the depth of discharge and life loss is not well defined, current practice with flooded cells is to limit the depth of discharge to 80% of the full battery capacity (the battery *rated* capacity may be defined as the capacity that can be used regularly while achieving a stated battery life).

Sealed batteries presently have a shorter life than flooded cells for the same depth of discharge. New designs may reduce this difference in performance between the two types. Of course, sealed batteries require less maintenance, and this may offset the shorter life. If the reduced life is a constraint for sealed batteries, the sealed types may have an advantage where cycling is infrequent or only partial cycles are needed, and spinning reserve or other uses are the primary function.

In some applications there will be value to the ability to discharge a battery fully. The cell capacity that remains after a normal-depth discharge may be used for spinning reserve or to backup transmission or distribution equipment. Manufacturers indicate that flooded cells can be discharged fully on occasion without significant loss of life. Sealed or valve regulated batteries may eventually have this capability. To achieve full discharge, the power converter must be capable of operating at the end-of-discharge battery voltage.

Flooded cell lead acid batteries are capable of more than 2,000 cycles in load-leveling applications to an 80% depth-of-discharge. Battery manufacturers will guarantee such performance with warranties that extend four years or more based on the number of cycles the battery is expected to perform in a given period. For similar cycle duty, a VRLA battery will offer a lower cycle life.

For applications such as frequency regulation, the battery experiences a shallow depth-of-discharge, and it is generally accepted that such light discharges do not affect battery life. The Puerto Rico Electric Power Authority (PREPA) 20 MW frequency regulation/spinning reserve duty battery (discussed later in this chapter), has a commercial warranty of 8 years. This battery will perform the shallow discharge frequency regulation on a continuous basis and be available for a deeper discharge to meet the spinning reserve requirements approximately once every week.

Rapid Cycling

There are two benefits that batteries can provide that will require the battery to be cycled more than once per day. One is frequency regulation and the other is tie line control or area control error (ACE) corrections. Frequency regulation will require many shallow cycles lasting only seconds or minutes. Tie line control cycles will be of modest depth, and will typically last 5 or 10 minutes. These cycles may be in addition to a normal diurnal storage cycle.

Batteries are useful for frequency regulation only in systems of modest size where variations in customer load are large compared to the total on-line generation. In these systems frequency will vary from second to second and minute to minute unless one or more generators are assigned to tightly control frequency. This kind of duty on generators reduces plant equipment life and increases maintenance. And, even the fastest plants may have difficulty following load, and some utilities do not attempt to regulate frequency tightly because of the cost. Batteries provide very rapid response to load changes. Batteries can easily meet the rapid load change response required for tight frequency control applications. A 17 MW/14 MWh battery has been used in Berlin since 1986 by the Berliner-Kraft-und Licht (BEWAG) for frequency regulation/spinning reserve applications. This battery has not shown any signs of capacity or life degradation and continues to operate as originally designed.

Large interconnected systems inherently control frequency well. Even the largest customer load variations are small compared to the mass of many turbine-generator rotors, and thus will not measurably change frequency. However, in these systems each utility has a responsibility of limiting variations in tie flow, or correcting variations quickly when they do occur. Tie flow variations can result from variations in customer load or unscheduled changes in the loading of generating plants. Batteries could provide a significant benefit by taking over the load following task from generators.

Response

A battery system can also be moved almost instantaneously from one operating point to another within its real and reactive operating range shown in Figure 1-2. In addition, it can *continuously* move about its operating region in response to a stabilizer or voltage regulator.

Fast response makes the battery a candidate to:

- Respond rapidly to generation shortages or transmission overload (via control signals from control center software or operators),
- Provide LFC or Area Regulation (via control signals from control center software),
- Tightly regulate voltage for the benefit of nearby customers or a larger load area,
- Regulate voltage for improved voltage stability in areas with little generation,
- Provide a damping component of power to raise transfer limits imposed by dynamic stability,

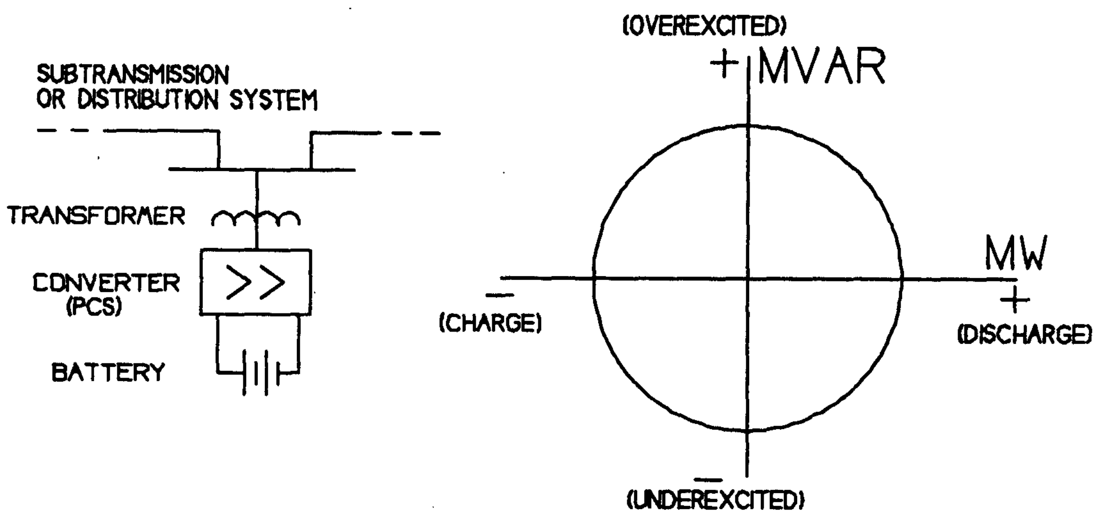


Figure 1-2. Real and Reactive Operating Range of Battery

In supplying reactive power to control voltage, the battery system is competing directly with Static Var Systems (SVSs) and generators. The battery system has an advantage over generators in that generators can rarely be sited where voltage control is needed, while batteries are very likely to be sited in areas needing voltage control. A battery system also responds much more quickly to system voltage changes than a generator can.

The reactive capability of a battery system converter is quite similar to that of an SVS. More information on this is in the next section.

Batteries as a Source of Reactive Power

A converter can supply reactive power to defer capacitors. It can also regulate voltage to improve power quality and system stability. Variations in voltage have become less tolerable to all customers so the contribution to power quality may be very significant.

GTO and transistor based power converters can provide or absorb reactive power as well as move active power into or out of the battery. The reactive power can be controlled rapidly just as the active power can, and thus allows a converter to regulate voltage. A battery cannot provide reactive power when the converter is being fully utilized to handle active power (charge or discharge), but can provide significant reactive power and voltage control at other times. However, a modest increase in converter rating will allow it to provide a large amount of reactive power while also operating at maximum battery charge or discharge rating.

Table 1-2 shows the cost of reactive power from a converter that costs $150 per kVA overall, but can be increased in size for $100 per kVA. The first column is the converter kVA rating per kW of battery rating, the second column is the dynamic kvar range per kW of battery rating that would be provided, the third column is the incremental kvar per kW at that converter kVA rating, the fourth column is the battery/converter power factor rating, the fifth column is the cost per incremental kvar, and the sixth column is the overall cost per kvar. A converter could, for example, be increased to 1.2 times the battery active power rating and still be competitive with an SVS that provides incremental kvar at $40/kvar. If the battery and its converter allow the SVS to be completely avoided, then the battery can be credited with the overall SVS cost which is on the order of $60/kvar. In this situation, the battery converter might be an attractive alternative to an SVS at well over twice the battery active power rating.

Equalization Charge

About once per week a cycled battery must be 'overcharged' a modest amount for several hours. This brings all cells to their maximum capacity, including 'slower' cells that may not achieve full charge during the daily cycle. The several hour period of overcharge does not damage or increase the charge in the 'faster' cells, but brings the 'slower' cells up to their maximum charge level. Both flooded and sealed cells need an occasional equalization charge.

Table 1-2
COST OF REACTIVE POWER

Converter kVA	Total kvar per kW	Incremental kvar/kVA	Power Factor	Cost per Incremental kvar	Overall Cost per kvar
1.00	0.0		1.00		
1.05	0.6	6.5	0.95	$15	$8
1.10	0.9	4.8	0.91	21	11
1.15	1.1	4.0	0.87	25	13
1.20	1.3	3.6	0.83	28	15
1.25	1.5	3.3	0.80	30	17
1.30	1.7	3.1	0.77	32	18
1.35	1.8	3.0	0.74	34	19
1.40	2.0	2.9	0.71	35	20
1.45	2.1	2.8	0.69	36	21
1.50	2.2	2.7	0.67	37	22
1.55	2.4	2.6	0.65	38	23
1.60	2.5	2.6	0.63	39	24
1.65	2.6	2.5	0.61	40	25
1.70	2.7	2.5	0.59	40	25
1.75	2.9	2.4	0.57	41	26
1.80	3.0	2.4	0.56	42	28
1.85	3.1	2.4	0.54	42	28
1.90	3.2	2.4	0.53	43	28

Efficiency

There are losses in the power converter and its associated transformers during both charging and discharging. There are also 'turn-around' losses within the battery in the form of heat during charging and discharging. Turn-around losses can be as high as 20% if the battery is charged and discharged at its maximum rate. Other losses include auxiliaries such as ventilation and lighting. Turn-around efficiency may be as low as 75% in daily deep cycle applications. Of course, losses will be very low in spinning reserve applications where the battery 'floats' much of the time.

Reliability

Battery energy storage systems have the potential to be very reliable. The three major components, the solid state power converter, the converter transformer, and the batteries, all have proven reliability records.

- The converter is much like a static var systems, an HVDC converter, and an adjustable speed drive converter. These devices have proven to be very reliable.

- The converter transformer is not significantly different from conventional transformers, and no different from the transformers associated with

HVDC converters. Life expectancy is 30 to 40 years and forced outage rates are negligible.

- Lead acid batteries are well proven in power plant, substation, automotive, and telephone, UPS, and other applications. The sealed cells for utility energy storage applications that are now being tested will almost totally eliminate routine maintenance. Sealed cells also eliminate watering mechanisms and filters that require routine maintenance. In addition, batteries are installed in 'strings' that can be removed for service with no impact on battery system power, and only modest impact on storage capacity.

The reliability and availability of battery systems *must* be high if all of their benefits are to be recognized. For instance, if a battery system in a distribution substation is to be allowed to defer transformer capacity in the station, it must provide reliability equal to that provided by larger transformers. Planners applying today's deterministic planning criteria may interpret this to mean that the battery system must be as reliable as the transformers in the station. This is unlikely to occur. However, a valid comparison of reliability is not provided by comparing the battery system to transformers. The battery, when charged, is a separate source of power, and is not affected by transmission outages upstream of the substation as is a transformer.

Availability

As noted in the reliability section, the battery availability is high because cells are arranged in strings so that one string can be maintained or repaired while others are operating. Transformer and circuit breaker failures are rare and should not measurably affect battery availability. The component most likely to cause outages is the converter. A single thyristor failure will take the battery out of service for several hours until replaced. A conservative design should reduce outages due to thyristor failures to one per year or less. Today thousands of adjustable speed drives (motors fed by converters to reduce energy use or provide speed control) are operating with very high availability, indicating that the very similar battery converters should be able to do the same.

Environmental

Lead acid batteries do contain hazardous materials, primarily lead. However, these materials are well contained and existing hazard control procedures cover their usage.

Acid spills are possible with flooded cell batteries, but the amount of acid contained in each battery module is small and easily handled by industrial spill containment kits. Acid spills do not occur with the VRLA battery because the acid is immobilized in the glass mat or in gel form.

Battery disposal at the end of battery life can be handled by a contractual disposal agreement with the battery supplier or a certified salvager. The lead acid battery manufacturing industry is actively involved in environmentally safe recycling of lead and has a large, regionally dispersed recycling infrastructure in place. According to recycling statistics compiled by the Battery Council International, a non-profit trade association, the recycling rate for lead acid batteries during 1989 was 95.3%.

Siting Flexibility

Flooded cell batteries carry only modest risk of harmful spills, while the sealed types carry essentially no risk of harmful spills. Gas release is minimal with the flooded cells and nonexistent with other types. Hence with public understanding there should be only modest concern with flooded cells, and little or no concern with other cell types. Hence placing batteries near residential or commercial areas is feasible, as illustrated by San Diego Gas and Electric's recent successful locating of a battery for a trolley project in a good residential area.

Battery systems may require less than an acre for the sizes that might be placed in areas where land values are high (20 to 40 MWH). Less land may be required where two floors can be used, perhaps one at grade level and one below grade level. Less land per kWh will be required for larger sizes.

The PREPA 20 MW Battery Project

The Puerto Rico Electric Power Authority (PREPA) battery project marks a significant milestone in the application of batteries by electric utilities in the U.S. because it is being undertaken as a purely commercial venture by PREPA. Outside cost-sharing or other financial support was not used to enhance the economic viability of the project, and internally it has been treated as a resource addition, not an R&D project.

The electric network in Puerto Rico experiences severe voltage drops due to the geographic location of load centers and the generation units. The system also needs additional reserve capacity to meet load growth in recent years. The options faced by PREPA were to install additional combustion turbines in several locations, or use battery energy storage systems. Their internal economic analysis, combined with the reliable operating experience of the BEWAG battery for frequency regulation, provided the basis for their choice in favor of the battery. The planning projections indicate that a total installed capacity of 120 MW is needed to meet PREPA's spinning reserve requirements. This total capacity will be installed in 6 blocks of 20 MW battery energy storage systems over the next few years. Each 20 MW battery will be sited in a different location in the PREPA network, so that it serves both the spinning reserve requirements as well as the frequency control function at key locations determined by the existing transmission network and the distribution of load centers.

According to the current schedule, the first battery will be on-line by mid-1993. The battery, power conversion system, main transformer and the AC switchgear have been purchased. The costs for these components are shown in Table 1-3, and reflect "actual" battery costs at the present time. However, the cost of the power conversion system, Item 3, Table 1-3, is very high. General Electric (GE) was the only supplier that submitted a bid for this subsystem. The design proposed by GE is identical to the power conversion system they designed for Southern California Edison's Chino Battery. This design was developed for that project in the early 1980's, and has not been reproduced since then. Thus, GE quotes this as a one-of-a-kind, high cost item. It is reasonable to expect that this subsystem cost can be substantially reduced for future battery projects, both due to refinements in design as well as increased vendor competition. A mature power conversion system should cost out at approximately $150 – $170/kW, compared to the current cost of $270/kW. This reduction in this subsystem cost will reduce the cost of the overall battery system substantially.

Table 1-3
PREPA 20 MW BATTERY PROJECT COSTS

Item	Cost	Unit Cost
1. Engineering Design	$1,000,000	
2. Battery (14.1 MWh)	$4,500,000	$319/kWh
3. Power Conversion System (20 MW)	$5,400,000	$270/kW
4. Main Transformer	$360,000	
5. AC Switchgear	$190,000	
6. DC Switchgear	$650,000	
7. Facility Control System	$800,000	
8. Construction Contract	$4,000,000	
TOTAL PROJECT COSTS	$16,900,000	$1,199/kWh $845/kW

CHUGACH ELECTRIC ASSOCIATION SITUATION

Chugach Electric Association's generation mix consists largely of natural gas-fired units as shown in Table 1-4. Cooper is hydroelectric; all other units are gas-fired. In addition to the CEA-owned units shown in the table, CEA receives substantial amounts of power and energy from the Bradley and Eklutna hydroelectric stations.

The CEA system is heavily winter-peaking. Winter peak is currently about 350 MW, while summer peak is about 220 MW. Under CEA's mid-case projection, winter peak is expected to grow to around 400 MW by the year 2000.[4] Annual load factor is about 63 percent. During the winter the daily peak occurs around 7 pm to 8 pm; during the summer it occurs about 12 noon to 1 pm.

4. These load figures include obligations to HEA, MEA, and SEA as well as CEA's own load.

Spinning reserve requirements are 38 MW. Although CEA currently "sells its spin" to Golden Valley Electric Association (GVEA), no such sales are included in the current analysis. The horizon of this analysis is the 25- to 30-year life of a battery system, beginning in the mid-1990s. GVEA sales may not be a significant factor during much of this horizon.[5]

Table 1-4
CHUGACH ELECTRIC ASSOCIATION GENERATING CAPACITY

Unit	Plant Type	Capacity (MW)
Beluga 1	Combustion Turbine	17
Beluga 2	Combustion Turbine	17
Beluga 3	Combustion Turbine	55
Beluga 4	Combustion Turbine	9
Beluga 5	Combustion Turbine	66
Beluga 6	Combustion Turbine[6]	78
Beluga 7	Combustion Turbine[6]	75
Beluga 8	Steam Turbine[6]	54
Bernice Lake 1	Combustion Turbine	8
Bernice Lake 2	Combustion Turbine	18
Bernice Lake 3	Combustion Turbine	25
Bernice Lake 4	Combustion Turbine	25
International 1	Combustion Turbine	16
International 2	Combustion Turbine	16
International 3	Combustion Turbine	19
Cooper	Hydro	17
	TOTAL	**510**

OVERVIEW OF THIS REPORT

Section 2 quantifies the generation benefits of batteries on the Chugach Electric Association system. Section 3 describes in detail the potential for reduced load shedding. Section 4 describes potential transmission and distribution investment deferral that could result from the addition of battery energy storage. Section 5 compares these benefits to the cost of installing batteries. Section 6 summarizes the results and recommends further steps.

5. In 1996 a 50 MW coal-fired unit is planned to go on-line at Healey. GVEA plans to take the total output from this plant, reducing the need to purchase economy energy from CEA.

6. The Beluga 6 and 7 combustion turbine units power the Beluga 8 steam unit through heat recovery, with the three units together forming a combined cycle plant. Either or both of the CTs can be operated independently without running the steam unit, and either CT can be operated along with the steam unit at some reduced output.

2

POTENTIAL GENERATION BENEFITS

This section estimates the magnitude of three kinds of generation benefits—load-leveling benefits, dynamic operating benefits, and environmental benefits—of adding battery storage to the Chugach Electric Association system. The section discusses the logic behind the calculations, describes the approach taken for the Chugach analysis, and presents the results.

CALCULATING GENERATION BENEFITS OF ENERGY STORAGE

Load-Leveling Benefits

Energy storage makes it possible to generate electricity during off-peak hours and use it during peaking-hours, commonly referred to as load-leveling. Typically, system lambda (the marginal cost of energy) is lower during off-peak hours than during on-peak hours; the load-leveling savings is the difference between the lambda during peaking hours when the storage would be discharged and the lambda for the off-peak hours, when the storage would be charged, adjusted for the efficiency loss from the battery.

$$\underset{(\$/\text{MWh})}{\text{Load Leveling Benefits}} = \underset{(\$/\text{MWh})}{\lambda_{\text{on-peak}}} - \underset{(\$/\text{MWh})}{\lambda_{\text{off-peak}}}/\text{storage efficiency}$$

If this number is positive, then there are load-leveling savings. This will be true if the battery efficiency exceeds the ratio of off-peak lambda to on-peak lambda.

Dynamic Operating Benefits

Dynamic operating costs (DOCs) are the portion of total operating costs of an electric power system required to meet dynamic operating requirements. Technologies that offer operating flexibility at minimal costs, such as energy storage plants, provide power systems with significant operating cost savings. These savings are called dynamic operating benefits (DOBs). Potential DOBs are measured as reductions in dynamic operating costs (DOCs). DOCs include:

- Startup costs, the costs of shutting down and starting up power plants.
- Load Following costs, increased fuel costs due to operations in load following mode.

- Minimum Load costs, costs due to foregone economic generation because of minimum load constraints.
- Ramping costs, the costs due to foregone economic generation because of ramping constraints.
- Frequency Regulation costs, costs of foregone economic generation due to externally constraining the loading ranges of some units to provide frequency regulation capabilities.

This study estimated the benefits associated with reducing the first three types of dynamic operating costs: startup costs, load following costs, and minimum load costs, all of which have a solid technical foundation based on common utility operations. Other categories of DOBs are likely to be smaller but can only add to the DOBs quantified in this study.

Startup Cost Benefits. The cost of starting a steam unit that has been shut down completely can be as much as several thousand dollars. Compared to the total daily operating cost of such a unit, this is not insignificant. By modifying unit commitment, the addition of battery storage can make it possible to avoid this startup cost for one or more units. Since CEA has no steam unit except for Beluga 8, which is part of a combined cycle plant, steam unit startup costs are not relevant to this study.

Load Following Benefits. Load fluctuation requires that some generation be able to meet changes in, or follow, the load. As a result of this requirement, the units used for load following will most of the time be loaded at levels other than their most efficient loadings, at points where their average fuel costs are higher than at their most efficient loadings and higher than system marginal cost. Load following benefits occur when a unit operating in load following mode is decommitted. The benefits or savings are equal to the difference in average energy cost of the unit and the system marginal energy cost.

Load following costs of a unit are the costs which could have been avoided were the system able to decommit the unit and replace its energy at the system marginal energy cost. These are calculated for hours where the unit is operated at part load (not on minimum load):

$$\begin{matrix}\textit{Load Following}\\ \textit{Costs of a Unit}\\ (\$/hr)\end{matrix} = \left(\begin{matrix}\textit{Average Energy}\\ \textit{Cost of the Unit}\\ (\$/MWh)\end{matrix} - \begin{matrix}\textit{System Marginal}\\ \textit{Energy Cost}\\ (\$/MWh)\end{matrix}\right) * \begin{matrix}\textit{Loading of Unit}\\ (MWh/hr)\end{matrix}$$

The daily load following costs are the sum of the hourly load following costs (for the hours in load following mode).

Minimum Load Benefits. Thermal units have minimum loading constraints. When they are committed, they must be operated at or above this minimum load. Operation at minimum loading generally results in the least efficient generation. Units are normally operated at their minimum load only because the constraint prohibits even lower loading. Minimum loading benefits occur when a unit operating at its minimum load is decommitted. The benefits or savings are equal to the difference in average energy cost of the unit and the system marginal energy cost.

Minimum loading costs of a unit are the costs which could have been avoided were the system able to decommit the unit and replace its energy at the system marginal energy cost, calculated for hours where the unit is on minimum load:

$$\begin{matrix}\text{Minimum Load}\\ \text{Costs of a Unit}\\ (\$/hr)\end{matrix} = \left(\begin{matrix}\text{Average Energy}\\ \text{Cost of the Unit}\\ (\$/MWh)\end{matrix} - \begin{matrix}\text{System Marginal}\\ \text{Energy Cost}\\ (\$/MWh)\end{matrix}\right) * \begin{matrix}\text{Minimum}\\ \text{Loading of Unit}\\ (MWh/hr)\end{matrix}$$

The daily minimum load costs are the sum of the hourly minimum load costs (for the hours at minimum load).

Figures 2-1 and 2-2 illustrate how minimum load and load following costs are calculated and how significant they can be. Although the figures are for a hypothetical unit in a hypothetical system, they are typical of actual units. The unit operates at its minimum load for hours 0-4 and 20-24, at its maximum load for hours 8-16, and in load-following mode during the other 8 hours. The daily load following cost of the unit is the dark shaded area in Figure 2-2; the light shaded area is the unit daily minimum load cost. The difference between unit average cost, which is the cost actually incurred, and system marginal cost, the cost that would be incurred if this unit could be shut down, is substantial.

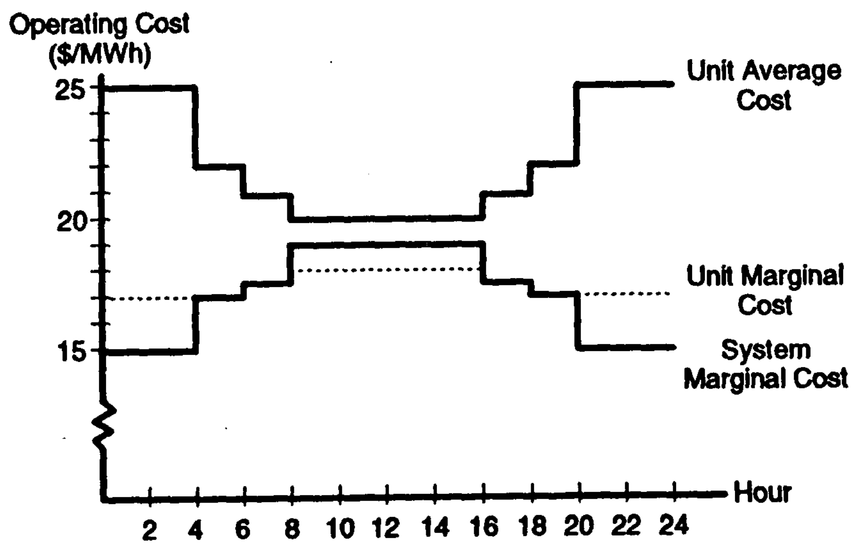


Figure 2-1. System and Unit Costs

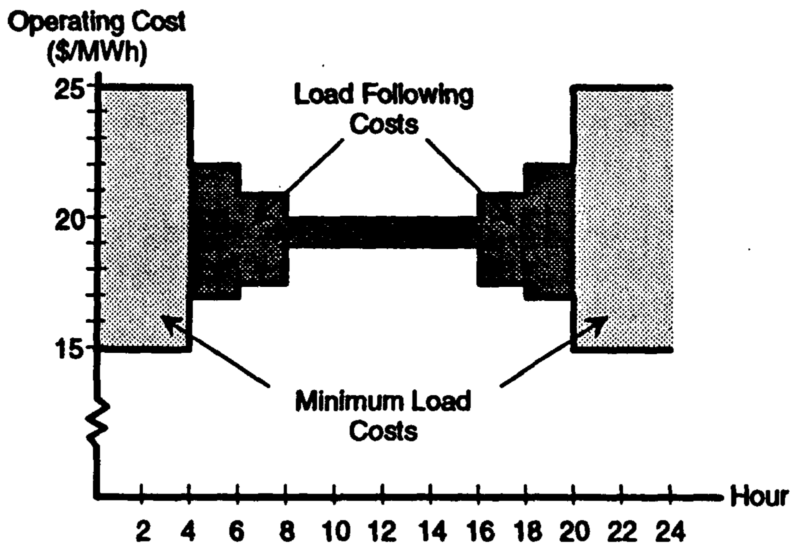


Figure 2-2. Load Following Costs and Minimum Load Costs

CAPTURING GENERATION BENEFITS OF ENERGY STORAGE

There are two primary modes in which storage can be operated:

- On a regular charge/discharge basis
- To provide spinning reserve only

Both modes are discussed below.

Charge/Discharge Application

Operated in this mode, storage provides not only load-leveling but also the reduction in dynamic operating costs made possible by decommitting a unit and operating remaining units at more efficient levels. The storage would most likely be operated on a daily cycle, with charging at night and discharging during the daily peak. In order to maximize benefits per kilowatt of battery capacity, it is necessary to install both enough power capacity (MW) and storage capacity (MWh or hours of storage) to permit decommitting one or more units.

To illustrate the importance of including dynamic operating costs in calculating generation benefits, consider a hypothetical system with two time periods per day, a peak period of 8 hours, and an off-peak period of 16 hours. The system marginal energy costs are $18/MWh during the peak period and $17/MWh during the off-peak period. Figure 2-3 illustrates these marginal energy costs and Table 2-1 illustrates the operating characteristics of one generation unit (called Unit A). Unit A operates at minimum load (50 MW) during the off-peak period and at 100 MW during the peak period. Figure 2-4 illustrates the power output of Unit A.

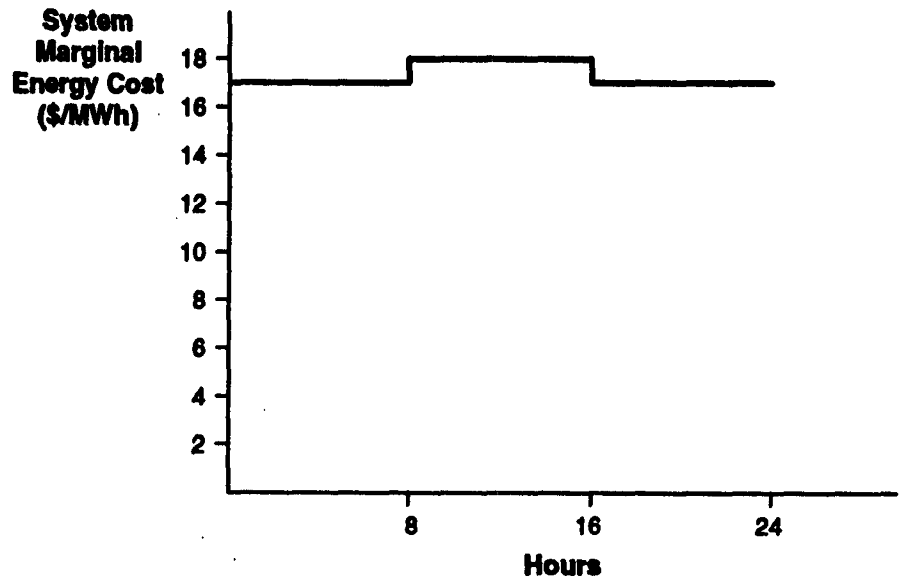


Figure 2-3. System Marginal Energy Costs

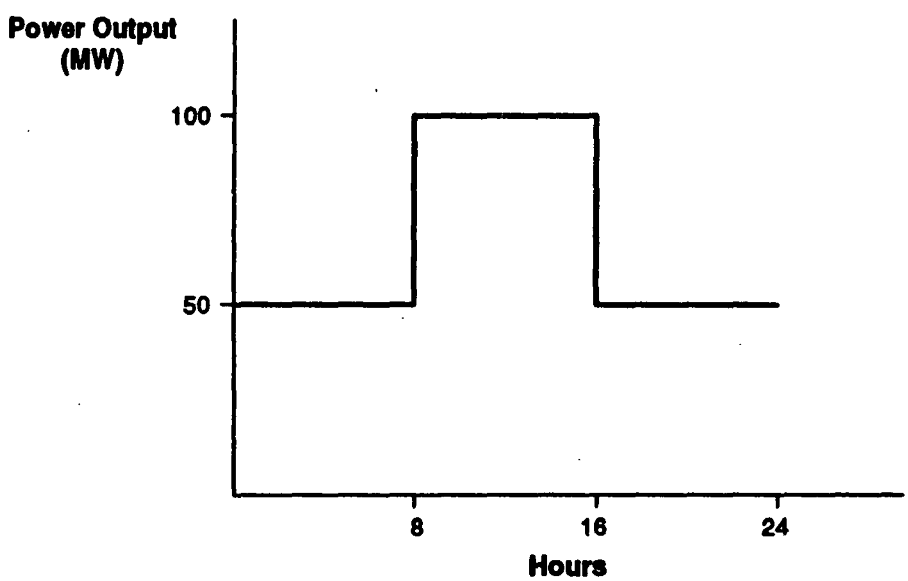


Figure 2-4. Power Output of Unit A

Table 2-1
OPERATING CHARACTERISTICS OF GENERATION UNIT A

Power Output (MW)	Average ($/MWh)	Marginal ($/MWh)
50	25.0	
100	21.0	17.0
150	20.0	18.0

Would a storage unit with a 77 percent cycle efficiency provide this system with any operating savings? Using the conventional approach (that does not include dynamic operating considerations), the benefit to cost ratio of storage operatings is calculated as follows:

$$B/C = 0.77 \times \frac{\textit{Marginal Energy Cost During the Peak Period}}{\textit{Marginal Energy Cost During the Off-Peak Period}}$$

$$= 0.77 \ \frac{18.0}{17.0}$$

$$= 0.815 < 1.0$$

Therefore, according to this calculation, storage operation is not economically feasible and would not provide any operating savings. To check the validity of this calculation, the benefit to cost ratio of operating the storage unit is explicitly calculated as:

$$B/C = \frac{\textit{Operating Savings of Energy Storage}}{\textit{Operating Costs of Energy Storage}}$$

The operating savings and costs of energy storage depend on the operations of the storage unit. One operating option is to charge during the off-peak period and discharge during the peak period to replace Unit A (we assume that there is enough power available during the off-peak period to provide the energy required for charging the storage unit and to replace the off-peak energy output of Unit A). The benefit to cost ratio of this operating option is calculated as follows:

$$\text{Required Charging} = \frac{100 \text{ MW x } 8 \text{ hrs}}{0.77} = 1{,}039 \text{ MWh}$$

$$\begin{aligned}\text{Charging Costs} &= 1039 \text{ MWh x } \$17/\text{MWh} \\ &= \$17{,}663\end{aligned}$$

Required Off-Peak Energy Replacement	= 50 MW x 16 hrs = 800 MWh
Costs of Replacing Off-Peak Energy	= 800 MWh x \$17/MWh
	= \$13,600
Total Costs of Replacing Unit A	= 17,663 + 13,600 = \$31,263
Total Savings by Replacing Unit A	= Total Operating Costs of Unit A
	= 100 MW x 8 hrs x \$21/MWh
	+ 50 MW x 16 hrs x \$25/MWh
	= \$36,800

The benefit to cost ratio of operating the storage unit to replace Unit A is therefore:

$$B/C = \frac{36{,}800}{31{,}263} = 1.177$$

Therefore, storage operation is economically feasible and would provide the system with operating savings. The implied dynamic operating benefits term, μ, which is missing from the conventional equation, can be calculated as:

$$B/C = 1.177 = 0.77\ \frac{18.0 + \mu}{17.0}$$

or

$$\mu = \frac{1.177 \times 17.0}{0.77} - 18.0 = \$7.98/MWh.$$

Spinning Reserve Application

As an alternative to using the battery as a charge/discharge unit, a utility could use a battery purely to provide spinning reserve with the following potential benefits: shut down least efficient units and allow generating units to operate at a higher load, thus reducing their average heat rates.

The following example illustrates the benefits from using a battery as spinning reserve. Consider a system consisting of three thermal units (Units 1, 2 and 3). System load is 200 MW, and spinning reserve of at least 40 MW is required. Table 2-2a shows the system dispatch without a battery. Without a spinning reserve requirement, units 1 and 2, the most efficient units, would have been able to meet the system load of 200 MW. Because of the spinning reserve requirement, all three units are operated; units 1 and 2 operate at 90 MW each and unit 3, the least efficient, is operated at its minimum load of 20 MW.

Table 2-2
USING A BATTERY TO PROVIDE SPINNING RESERVE

(a) Unit Loadings and Operating Costs Without Battery

	Min. Load (MW)	Max. Load (MW)	Ave. Cost at Max. Load ($/MWh)	Actual Load (MW)	Ave. Cost at Actual Load ($/MWh)	Spinning Reserve (MW)	Total Cost ($/hr)
Unit 1:	20	100	24.5	90	25	10	2,250
Unit 2:	20	100	24.5	90	25	10	2,250
Unit 3:	20	40	30	20	40	20	800
Total				**200**		**40**	**5,300**

(b) Unit Loadings and Operating Costs With Battery

	Min. Load (MW)	Max. Load (MW)	Ave. Cost at Max. Load ($/MWh)	Actual Load (MW)	Ave. Cost at Actual Load ($/MWh)	Spinning Reserve (MW)	Total Cost ($/hr)
Unit 1:	20	100	24.5	100	24.5	0	2,450
Unit 2:	20	100	24.5	100	24.5	0	2,450
Unit 3:	20	40	30	0	0	0	0
Battery:	0	40	0*	0	0*	40	0
Total:				**200**		**40**	**4,900**

* The operating cost of a battery providing only spinning reserve is really the fuel cost of keeping the battery charged. However, this cost is negligible in this context.

Dynamic operating costs resulting from the spinning reserve requirement are of two types. First, there is the cost of operating Units 1 and 2 at other than their most efficient level. Second, there is the extra cost of operating Unit 3, which is the difference between the average generation cost at Unit 3 and what it would have cost to generate the same load at Units 1 and 2.

Adding a battery changes the system operation, as displayed in Table 2-2b. Units 1 and 2 can now operate at full capacity, and Unit 3 is shut down entirely; the battery provides the required spinning reserve. For the particular hour shown in the tables, the savings per MWh of spinning reserve is ($5300 – $4900)/40 MWh = $10/MWh.

The spinning reserve benefits of using a battery in this manner can be summarized as follows: Unit 3, the least efficient unit, can be shut down and units 1 and 2 do not have to provide spinning reserve, and can operate at their most efficient loadings. The battery provides all required spinning reserves, and the system total operating costs are substantially lower.

STUDY APPROACH

The potential generation benefits from adding battery storage to Chugach Electric Association's system were determined by examining planned system operations as determined by running the production simulation model MAINPLAN for the Chugach Electric Association system. For the years 1994, 1996, and 2000, 6 representative days in each year were selected, a weekday and a weekend day during winter, summer, and fall/spring. The study focused on the marginal units (defined below) on these 18 days and determined how the operation of these units could be economically modified if sufficient battery storage were present on the system. Since previous studies[1] had shown the high cost of providing spinning reserve, this study focused on using batteries only to provide spinning reserve.

Hourly system loads for the 18 days are shown in Appendix A. For most of the days, baseload units operate 24 hours a day, and are supplemented by peaking units and firm purchases during the day, usually from about 7 am to 12 pm. The daily peak typically occurs between 5 pm and 11 pm. For some days, none of the thermal peaking units are operated at all. On those days, hydroelectric units and firm purchases provide the necessary peaking power.

Chugach Electric Association's marginal energy costs (system lambda) for the same 18 days, shown in Appendix B,[2,3] generally change very little during a 24-hour period. Typically, however, system marginal costs are lower during off-peak hours than during on-peak hours, but not by enough to make load-leveling economic. For Chugach Electric Association, the marginal cost is roughly proportional to natural gas prices, which increase from year to year; the average nominal fuel price is about $1 per million Btu in 1994, $2 in 1996, and $2.50 in 2000.

Generating benefits of energy storage were for 5 gas-fired units on Chugach Electric Association's system for each of the 18 days. These five units were selected as the marginal units whose operation would most likely be affected by the addition of batteries to the system. That is, they would be potential candidates for decommitment. Larger gas-fired units were

1. *Railbelt Intertie Reconnaissance Study*, prepared by Decision Focus Incorporated for the Alaska Power Authority, June 1989; *Economic Feasibility of the Proposed 138 kV Transmission Lines in the Railbelt*, prepared by Decision Focus Incorporated for Railbelt Electric Utilities, December 1989; 2/15/90 memorandum from Tim Newton, Planning Engineer, Chugach Electric Association.

2. The hourly marginal costs are for on-system units only.

3. System load shapes and information on individual units were all provided by Chugach Electric Association. The hourly system marginal costs were calculated by multiplying the fuel price times the marginal heat rate of the least efficient operating unit for each hour of the day.

excluded because they were too large to be replaced by batteries. Smaller units, including IGT 1, 2, and 3, were excluded because they did not operate at all on the 18 days considered. The key cost/performance characteristics of the units included in this study are displayed in Table 2-3.

Table 2-3
CHUGACH ELECTRIC ASSOCIATION GENERATING UNIT CHARACTERISTICS

	Minimum Load (MW)	Maximum Load (MW)	Startup Cost ($)	Heat Rate at Minimum Load (Btu/kWh)	Heat Rate at Maximum Load (Btu/kWh)
Beluga 1	3	17	0	35,573	15,304
Beluga 2	3	17	0	38,928	13,250
Bernice 2	3	18	0	36,626	14,835
Bernice 3	3	25	0	42,810	13,462
Bernice 4	7	25	0	24,126	13,815

STUDY RESULTS

Load-Leveling Benefits

As shown in Appendix A, system lambda is relatively flat across the 24 hours in each day. Combined with a battery efficiency of 75 to 80 percent, this means that there would be no load-leveling savings from batteries in the CEA system.

Many previous studies on energy storage have used only the load-leveling savings in quantifying the value of energy storage. Doing so here would lead to the conclusion that batteries are clearly uneconomic, and should not be considered further. As shown below and in the next sections, however, there can be significant savings from batteries even if load-leveling is uneconomic.

Dynamic Operating Benefits

The generation benefits resulting from adding batteries to the Chugach Electric Association system are summarized in Table 2-4. For each of the 18 days considered, the table shows the dynamic operating savings—in current year dollars—that could be realized if enough battery capacity were added to completely decommit the unit labelled "displaced unit".

Table 2-4
CHUGACH ELECTRIC ASSOCIATION SUMMARY OF GENERATION BENEFITS
NET OPERATING BENEFITS

Year	Season	Day	Day Type	Date	Net Operating Benefits ($/kW-year)	"Displaced Unit"
1994	Winter	Sunday	W-end	01/30/1994	25.09	Beluga 1
		Thursday	W-day	02/03/1994	24.00	Beluga 1
	Summer	Sunday	W-end	06/26/1994	0.00	
		Thursday	W-day	06/30/1994	0.00	
	Spring/Fall	Sunday	W-end	10/02/1994	20.14	Beluga 2
		Thursday	W-day	10/06/1994	25.12	Beluga 2
Estimated Annual Net Operating Savings					**17.92**	
1996	Winter	Sunday	W-end	02/04/1996	5.86	Bernice 4
		Thursday	W-day	02/08/1996	61.78	Beluga 2
	Summer	Sunday	W-end	06/30/1996	66.18	Beluga 2
		Thursday	W-day	07/04/1996	43.05	Bernice 4
	Spring/Fall	Sunday	W-end	10/06/1996	43.04	Bernice 4
		Thursday	W-day	10/10/1996	74.63	Bernice 4
Estimated Annual Net Operating Benefits					**54.99**	
2000	Winter	Sunday	W-end	01/30/2000	7.41	Bernice 4
		Thursday	W-day	02/03/2000	65.87	Beluga 1
	Summer	Sunday	W-end	06/25/2000	7.10	Bernice 4
		Thursday	W-day	06/29/2000	50.99	Bernice 3
	Spring/Fall	Sunday	W-end	10/01/2000	0.00	
		Thursday	W-day	10/05/2000	0.00	
Estimated Annual Net Operating Benefits					**25.62**	

The "displaced unit" is the unit for which the greatest savings could be obtained by decommitting the unit. The column in Table 2-4 labelled "Net Operating Benefits" expresses the savings in terms of dollars per year of battery capacity, assuming that the battery is the same size as the displaced unit and that all 365 days of the year were identical to the one for which the calculation is being made. The "annual net operating benefit" value is the weighted average of the daily values based on the number of weekdays and weekend days in each season during the entire year.[4]

As defined in Table 2-4, net operating benefits include all dynamic operating benefits, i.e., load following cost savings and minimum load cost savings. Most of the dynamic operating cost savings from Chugach Electric Association's system result from minimum load cost savings, which are on the order of thousands of dollars per day for each of the five marginal units. Load

4. The definitions of the seasons were as follows:

Winter	4 months
Summer	3 months
Fall/Spring	5 months

following costs are in the order of hundreds to thousands of dollars per day for each of the five units.

Figures 2-5, 2-6, and 2-7 show the actual MW loadings for three of the marginal units for the days on which the dynamic operating cost savings would be greatest from decommitting these units. Most of the time, the units operate far from their most efficient loadings (17 MW for Beluga 1 and 2, and 25 MW for Bernice 4).

The dynamic operating benefits for each day are shown graphically in Figures 2-8, 2-9, and 2-10, for the years 1994, 1996, and 2000, respectively. As a result of higher utilization of peaking units during weekdays, dynamic operating benefits are generally higher on weekdays than during the weekend.

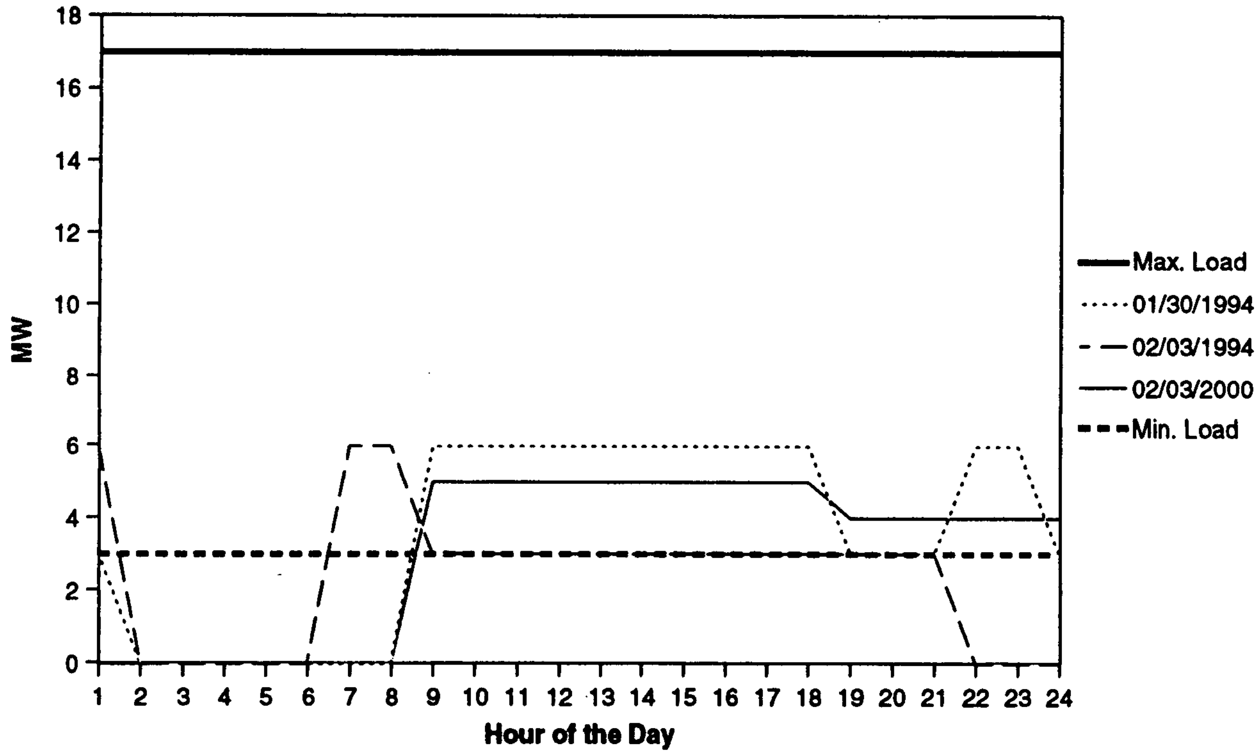


Figure 2-5. Daily Load for Beluga 1 Combustion Turbine Unit

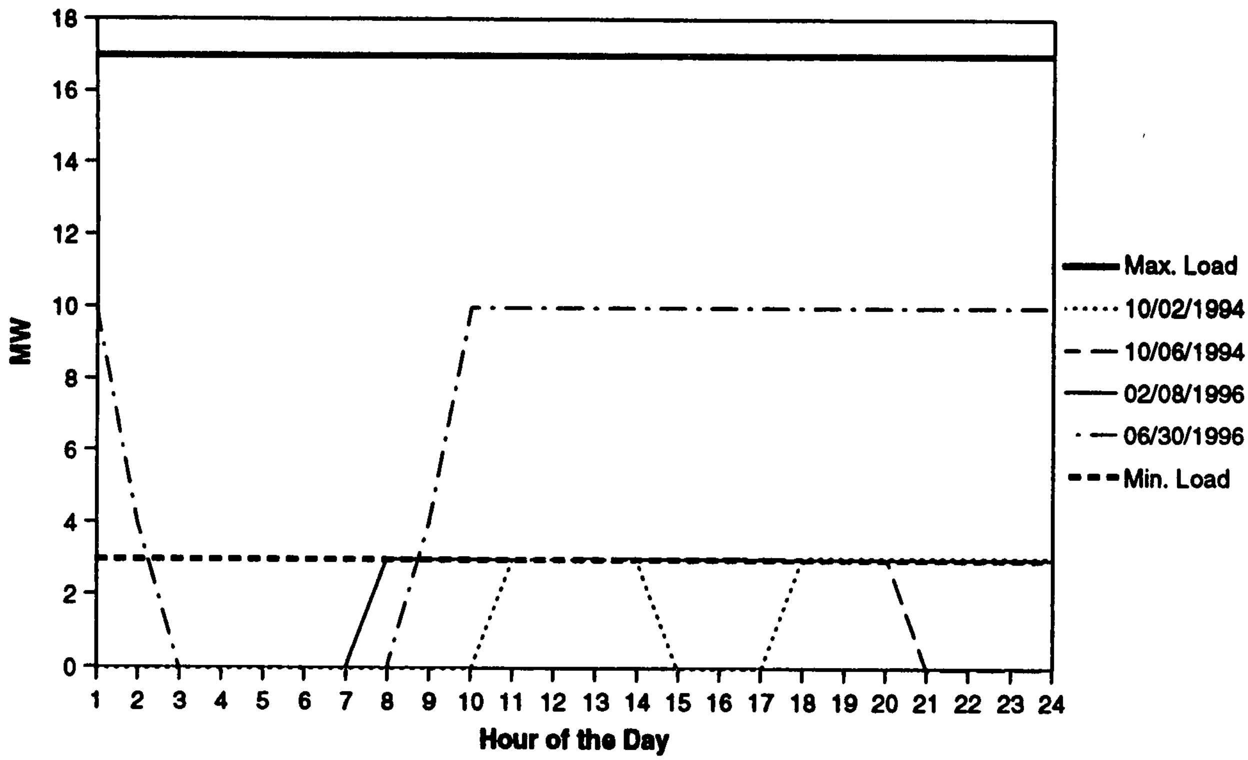


Figure 2-6. Daily Load for Beluga 2 Combustion Turbine Unit

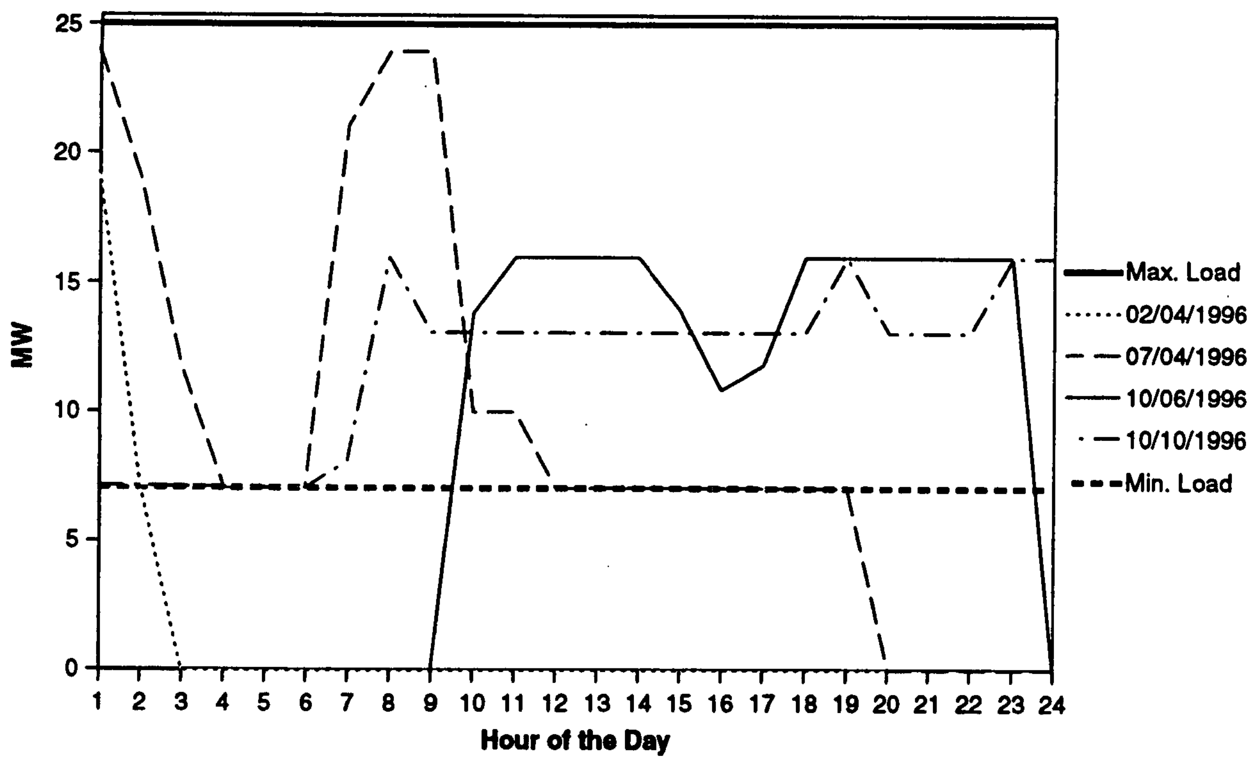


Figure 2-7. Daily Load for Bernice 4 Combustion Turbine Unit

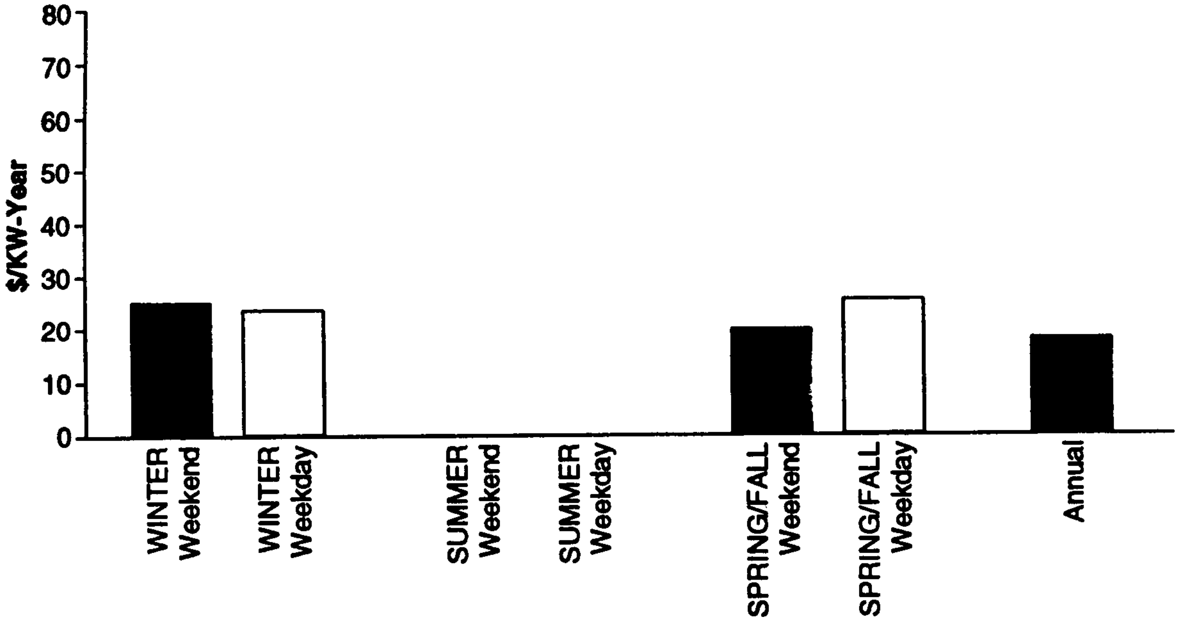


Figure 2-8. Net Operating Benefits In 1994

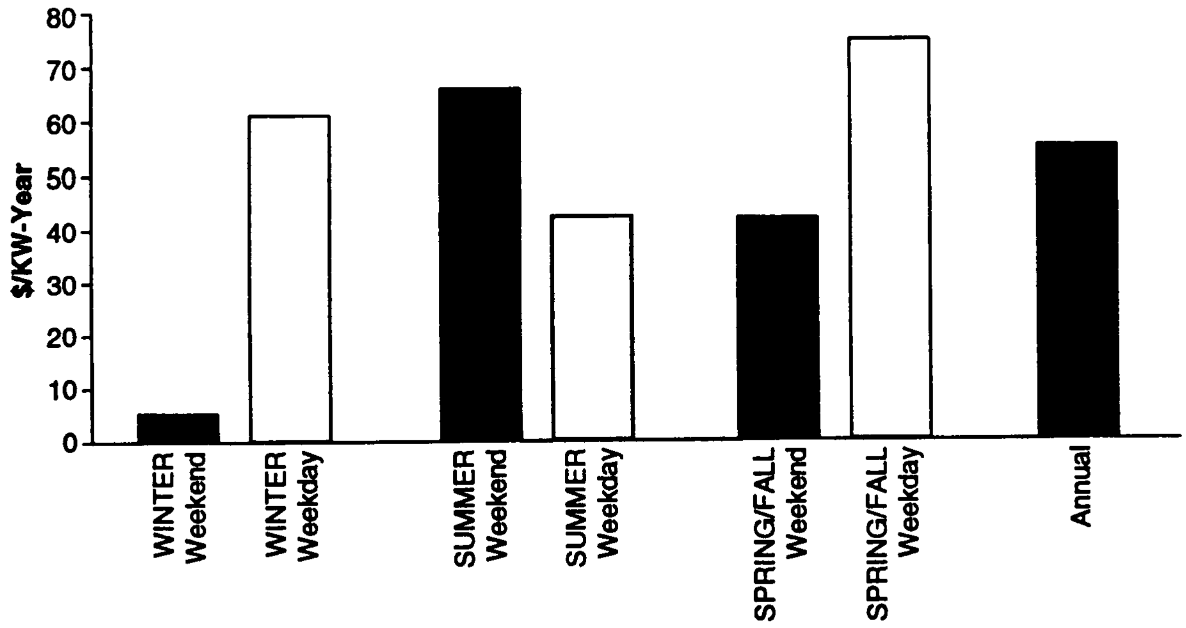


Figure 2-9. Net Operating Benefits In 1996

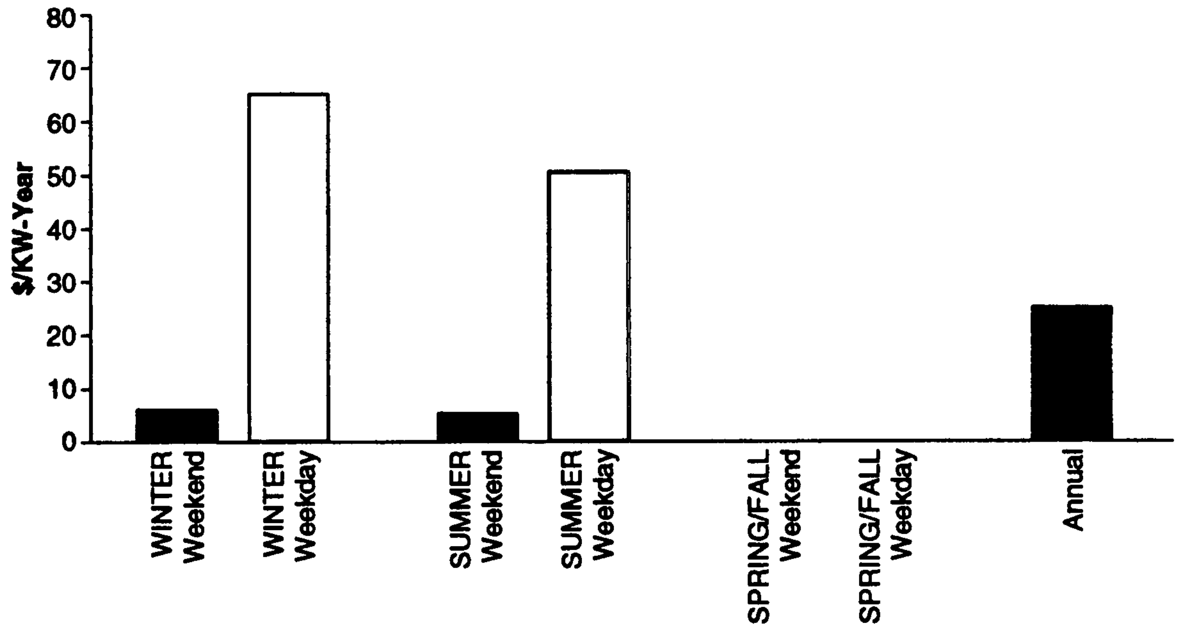


Figure 2-10. Net Operating Benefits in 2000

Why do the net operating benefits vary so much from year to year and even from day to day within each year? Why are they substantial on some days and zero on others? The variation is due primarily to four factors:

1. Increases in natural gas prices from year to year.

2. Differences in loads between weekdays and weekends.

3. Differences in loads among seasons.

4. Load growth from year to year.

Higher natural gas prices mean higher system lambdas and higher average fuel costs. Since net operating benefits are roughly proportional to the difference between average fuel cost and system lambda, both of which are roughly proportional to fuel price, higher fuel prices translate directly to higher net operating benefits.

The differences in loads across days, seasons, and years translate directly to differences in system operation. In particular, the units identified as marginal are sometimes operated 24 hours of the day, sometimes only a few hours of the day, and sometimes not at all. This is the direct cause of the huge variation in net operating benefits. In particular, for the days with no benefits, none of the marginal units operated at all.

One might expect that as load grows, the marginal units would be operated more hours. This is not necessarily the case, however. In general, MAINPLAN or any other production simulation operates the set of units that minimizes costs. Since larger units typically are more efficient, operating a few large units is preferred to operating many small units. For the CEA system at relatively low loads (Summer, 1994), only the two largest, most efficient thermal units operate, and there are no potential savings from batteries. At higher loads (Spring/Fall, 1994), smaller, less efficient units must also operate to provide spinning reserve; these units could be decommitted if the system contained enough battery storage, yielding substantial benefits. At still higher loads (Spring/Fall, 2000), the smaller thermal units are replaced by a third large, efficient unit (Beluga 3), and there are no small units to decommit. At yet higher loads (Winter, all three years), smaller units are again required, and there are potential savings from decommitting these smaller units if there is enough battery capacity. Thus, for the CEA system as simulated by MAINPLAN, there is no simple correlation between load levels and the operation of smaller units.

Three limitations were made necessary by the screening nature of this analysis. First, we considered only a limited number of days in each year, leading to "all or nothing" results, best exemplified by the values of net operating benefits for the different days in the year 2000. As a result of looking at such a small number of days, chosen before examining system operation and before calculating the benefits of storage on these days, the benefits for 1994 and 2000 are probably underestimated, while those for 1996 are probably overestimated.

Second, the results are based on the outputs of a production simulation model, which indicate that on many days the marginal units do not operate at all. In practice, the marginal units may operate more than indicated by the production simulation, yielding greater benefits from using batteries to decommit the marginal units.

Third, we calculated benefits only when it was possible to decommit a marginal unit for the whole day in question. However, it is possible that even on days when none of the five marginal units operates, operation of other units could be modified to produce operating benefits. For example, on October 1, 2000, none of the marginal units operates. However, three thermal units—Beluga 3, Beluga 68, and Beluga 78—are all operating with substantial slack capacity for several hours. With 20 to 25 MW of battery capacity on the system, Beluga 3 could be replaced by the excess capacity of the other two units from 2 am to 9 pm, providing substantial dynamic operating benefits.

Taking these limitations into account, annual net operating benefits of $40 to $70 per kW of battery capacity per year, levelized in current dollars, would seem a reasonable estimate of the generation benefits of adding battery capacity to the CEA system.

3

SPINNING RESERVE/LOAD SHEDDING BENEFITS

INTRODUCTION

This section describes the effectiveness of utilizing a battery energy storage facility in lieu of carrying actual spinning reserve on the combustion turbines of the Chugach Electric Association (CEA) system. Cases have been run to determine how various battery facility sizes will affect load shedding in the CEA system when combined with various levels of combustion turbine spinning reserve on the Railbelt system.

Load shedding may occur following the loss of a generating unit in the Railbelt system. The load shedding which occurs is a function of the number of generating units on-line and the amount of spinning reserve. As an alternative to carrying spinning reserve on generators, a battery of sufficient size can be used to reduce the frequency decay following a resource deficiency and prevent load shedding. To study the effectiveness of a battery, a number of parametric case studies have been executed. In each case, a loss of generation is introduced and the frequency decay and load shedding responses are observed.

Previous studies of the Railbelt system have shown that generator spinning reserve must be delivered quickly following a resource deficiency in order to minimize load shedding. Combustion turbines are the only type of resource on the Railbelt system which can provide "fast spin." Therefore, in this study, only combustion turbine spinning reserve was considered when calculating available spinning reserve levels. Hydroelectric and steam units were considered to have too slow of a response to provide sufficient spinning reserve to prevent or reduce load shedding.

Winter peak and summer normal load conditions have been evaluated. The winter peak load condition corresponds to the highest load level and therefore the highest levels of generation (i.e., largest number of on-line generators and maximum system inertia levels). Loss of a heavily loaded generator under such conditions will cause a moderate decrease in frequency at a relatively slow rate. Underfrequency load shedding in the CEA system can occur under such conditions if combustion turbine spin is not adequate. However, overshedding of load is usually not a problem.

Under summer normal load conditions, the number of generators on line is at a minimum. Loss of a large generating unit is a problem due to the lack of inertia on the system.

Under such conditions, large frequency deviations are likely with a fast rate of frequency decay. This can result in overshedding of load (i.e., load shedding greater than necessary.)

For the winter peak load condition, four scenarios have been studied. These scenarios differ by the amount of combustion turbine spinning reserve on the Railbelt system and/or the amount of load shed in lieu of actual spin. In all four scenarios, the disturbance consists of moderate size loss of generation (Beluga #8 at 54 MW). For two scenarios, a 95 MW loss of generation (AMLP #6 & 7) is also studied.

For the summer load condition, three scenarios are studied. These three scenarios differ by the amount of combustion turbine spinning reserve on the system and the number of combustion turbines which are used to provide the spin. From these case studies, the effectiveness of a battery storage facility to provide spinning reserve for the CEA system is determined. The scenarios considered in this study are summarized in Table 3-1.

Table 3-1
SUMMARY OF CEA LOAD SHEDDING ANALYSIS
Spinning Reserve Requirement of Railbelt System = 112 MW

Initial Conditions	CT Spinning Reserve Deficit or Surplus w/o Battery (MW)	Battery Sizes (MW)	Loss of Generation (MW)	Load (MW)
Winter Peak Load				
Scenario 1: Railbelt Spinning Reserve Requirements Met	CEA = −15.6 AMPL = +26.3 GVEA+FMUS = −9.2 Total = +1.5	0,15,20,25,30	54	692
Scenario 2: Railbelt Spin Not Met; CEA Deficit of 15 MW	CEA = −15.4 AMLP = −4.7 GVEA+FMUS = −9.2 Total = −29.3	0,15,20,25,30	54	692
Scenario 3: Spin Not Met; CEA Deficit of 15 MW; GVEA Load Shed in Lieu of Spin	CEA = −15.4 AMLP = −4.7 GVEA+FMUS = −9.2 Total = −29.3	0,15,20,25,30,40	54,95	692
Scenario 4: Spin Not Met; CEA Deficit of 40 MW; GVEA Load Shed in Lieu of Spin	CEA = −39.6 AMLP = −4.7 GVEA+FMUS = −9.2 Total = −53.5	0,15,20,25,30,40,50	54,95	692
Summer Load				
Scenario 5: Spin Not Met; Beluga #1 & #2 On; GVEA Load Shed in Lieu of Spin	CEA = +11.1 AMLP = −9.2 GVEA+FMUS = −9.2 Total = −7.3	0,15,20,25	50	254
Scenario 6: Spin Not Met; Beluga #1 On, #2 Off; GVEA Load Shed in Lieu of Spin	CEA = −4.9 AMLP = −9.2 GVEA+FMUS = −9.2 Total = −23.3	0,15,20,25	50	254
Scenario 7: Spin Not Met; Beluga #1 & #2 Off; GVEA Load Shed in Lieu of Spin	CEA = −19.9 AMLP = −9.2 GVEA+FMUS = −9.2 Total = −38.3	0,15,20,25	50	254

It should be noted that in some of the scenarios shown in Table 3-1, the Railbelt as a whole or particular utilities are deficient in the required amount of spinning reserve. In some scenarios, it is assumed that surplus spin in one utility is used to cover the spinning reserve requirements of another. These scenarios are a departure from the way the spinning reserve is handled in actual practice. These scenarios were established merely to create varying levels of spinning reserve on the Railbelt system for analysis of battery size options and benefits. Thus, the feasibility and cost/benefits of reserve sharing were not considered in the analysis.

CONCLUSION

For both load conditions studied, a battery storage facility is effective in reducing or preventing load shedding in the CEA system. For the lightly loaded system condition, a battery facility of sufficient size to eliminate load shedding on the CEA system also eliminates load shedding in the Fairbanks area.

A battery installed in the CEA system provides the following benefits in the event of a moderate loss of generation (54 MW) on a heavily loaded system. The 15 MW battery will provide enough spinning reserve to prevent load shedding if the CEA system has a 15 MW deficit in its combustion turbine spinning reserve requirement and the rest of the system is no more than 5 MW deficient. In the event that the CEA system is 40 MW deficient of combustion turbine spinning reserve, a 25 MW battery will prevent load shedding on the CEA system. A 25 MW battery will also prevent load shedding in the CEA system if CEA is 15 MW deficient and the remainder of the Railbelt system is 15 MW deficient in combustion turbine spinning reserve.

In the event of a large loss of generation (95 MW) on a heavily loaded system, the battery facility provides the following benefits. For Scenario 3, where there is a 29 MW deficit (without the battery) in the Railbelt system combustion turbine spinning reserve, a 30 MW battery will reduce CEA load shedding to 23 MW and a 35 MW battery will eliminate CEA load shedding. For Scenario 4, which has a 54 MW spinning reserve deficit (without the battery), a 40 MW battery will limit CEA load shedding to 23 MW. This is compared to 62 MW of load shedding that occurs in the CEA system if only a 30 MW battery is used.

For the lightly loaded system, replacing part of the spinning reserve provided by combustion turbines with a battery eliminates or reduces the amount of load shedding in the CEA system. The more spinning reserve that is provided by battery energy storage in lieu of combustion turbine spinning reserve, the less load shedding that will occur. This is the case even when system inertia is reduced by removing the combustion turbine units which are carrying the spin. This is due to the extremely fast response of the battery as compared to the response of the combustion turbines.

STUDY CONDITIONS

A battery storage facility, as modeled in this study, can provide its full rating nearly instantaneously. Moreover, the output of a battery facility can be cycled around some desired operating point continuously on a repetitive basis. The amount of power that the battery supplies is directly proportional to the frequency deviation in the system. The droop setting of the battery controller can be set to provide full battery response to small underfrequency deviations. Thus, the nature and characteristics of a battery storage facility allow droop settings as low as 0.5 to 1.0%. A controller droop setting of 1.0%, for example, would allow a battery to go from zero to full output as the frequency decreases from 60 Hz to 59.4 Hz.

Generators are a mechanical system and have some finite "cycling" capability. Furthermore, for parallel operation, some significant amount of droop is necessary in generator governors in order to achieve control stability. Thus, generators in the Railbelt system have droops of approximately 4 to 5%. Also, since generators have some finite response rate capabilities, smaller droops would not necessarily translate to a faster response to frequency deviations. Smaller droops would only minimize the steady-state frequency deviation. Smaller droops would also increase the "cycling" of the generators in response to system frequency deviations.

Because the first stage of load shedding in the CEA system operates at 59.3 Hz (i.e., backup load shedding relays), a droop of 1% appears to be a reasonable objective for a battery storage facility. This assures the battery will supply its full rating before load shedding relays in the CEA system operate.

The droop of the controller of the battery can be reduced. Generally the lower the droop setting, the lower the overall system frequency deviation. Moreover, since the speed of response of a battery storage facility is (for all practical purposes) unlimited, smaller droops also reduce the rate of frequency decay following a resource deficiency. Cases were run to validate this assumption.

A battery with smaller droop was not always found to be advantageous. In certain situations, a battery with a very small droop (0.5%) deferred the actuation of "load shed in lieu of spin" in the GVEA area thereby increasing load shedding in the CEA area. Thus, from the perspective of the CEA system, the optimum battery facility droop will be one which causes the battery to reach full output before the CEA load shedding relays operate, but will not delay load shedding which should occur elsewhere in the Railbelt system. Based on current load shedding relay settings, 1% appears to be the best droop setting for a battery facility on the CEA system.

For this study, the effectiveness of batteries ranging in size from 15 to 50 MW is studied. In some cases, the battery cannot prevent load shedding. However the battery can reduce the amount of load shedding in the CEA system. By running the same case without a battery, this reduction in load shedding is determined.

The effectiveness of a battery to reduce load shedding, as summarized in Tables 3-2 through 3-5 below, would be different if the first load shedding point used on the CEA system were lower. The representation of CEA's backup relays which operate at 59.3 Hz require the use of a larger battery in order to eliminate load shedding on the CEA system. If the first step of load shedding on the CEA system occurred at 59.2 Hz (the first stage of CEA's normal load shedding relays), smaller size batteries would appear more beneficial. Moreover, load shedding in the CEA system would occur at the same point as load shedding in the AMLP system. As shown in Tables 3-2 through 3-5, the use of CEA's backup relays accounts for the load shedding in the CEA system when none occurs in the AMLP system.

The following response data is plotted for each case: frequency and voltage at the International 34.5 kV bus, battery power output, and battery controller output. The simulations were performed using PSS/E, the Power System Simulator for Engineering, developed by Power Technologies, Inc.

SPINNING RESERVE REQUIREMENTS

The spinning reserve requirement for the Railbelt system is equal to the capacity of the largest on-line unit, or unit pair in the case of combined cycle units. For these studies, the largest "unit" is the AMLP Unit #6 and #7 combined cycle pair. Winter capacity of these units is 112 MW and summer capacity is 95 MW.

For the two load conditions considered in this study, the spinning reserve requirements for each utility are as follows. For simplicity, the GVEA and FMUS system are combined.

WINTER PEAK LOAD			SUMMER NORMAL LOAD		
GVEA + FMUS	=	19.2 MW	GVEA + FMUS	=	19.5 MW
CEA		44.9 MW	CEA		32.3 MW
AMLP		47.9 MW	AMLP		43.2 MW
TOTAL	=	112.0 MW	TOTAL	=	95.0 MW

DISCUSSION

Winter Peak Load

The winter peak load scenarios studied are outlined in Table 3-1. This section covers each scenario in more detail and identifies the effectiveness of using various size battery facilities. The generation schedule for each scenario are given in Appendix B. Also, for Scenarios 3 and 4, the GVEA system provides 9.2 MW of load shedding in lieu of spin to compensate for its lack of combustion turbine spinning reserve.

Scenario 1

In Scenario 1, Golden Valley and Fairbanks have 10 MW of combustion turbine spinning reserve. Therefore they have a spinning reserve deficit of 9.2 MW. CEA has 29.3 MW of combustion turbine spinning reserve without the battery for a deficit of 15.6 MW. AMLP has 74.2 MW of combustion turbine spinning reserve and therefore has 26.3 MW extra. Thus the Railbelt system as a whole has combustion turbine spinning reserves of 113.5 MW; a slight surplus.

For Scenario 1, the initial case is run without a battery. Loadshed in lieu of spin in the GVEA system is not utilized. Four different battery sizes are also represented (15, 20, 25 and 30 MW), and two different droop settings (0.5% and 1%), are used. A disturbance is produced by tripping the Beluga #8 unit (54 MW). The plotted responses are shown in Appendix C. It can be seen that for all cases with a battery, load shedding does not occur in any utility. If no battery is used, load shedding occurs as follows:

FMUS sheds	2.7 MW	GVEA sheds	11.5 MW
CEA sheds	0 MW	AMLP sheds	0 MW

This load shedding is limited to the Fairbanks area, but it slightly exceeds the amount of load which would need to be shed as "load shed in lieu of spin." As expected, frequency deviation decreases as battery size increases. With the 15 MW battery, frequency settles at 59.4 Hz. With the 25 MW battery, frequency settles at 59.6 Hz. Marginally superior performance for all cases is achieved if the battery droop is set at 0.5%. The frequency deviations are smaller and the steady state frequency is slightly higher.

Scenario 2

Scenario 2 differs from Scenario 1 by the amount of spinning reserve available to the system as shown in Table 3-1. AMLP Unit #8 (85 MW capability), running at 23.8 MW in Scenario 1, is replaced with Units #1 and #5 which have a 17 MW and 37 MW capability respectively. This reduces the spinning reserve of AMLP by 32 MW with respect to the Scenario 1. AMLP is now 4.7 MW deficient in combustion turbine spin, CEA is still 15.4 MW deficient without a battery, and GVEA and FMUS are still 9.2 MW deficient. The Railbelt system as a whole is deficient by 29.3 MW without a battery.

Studies were run without a battery and with 15, 20, 25 and 30 MW batteries at 0.5% and 1% droop. A disturbance is introduced by tripping the Beluga #8 unit (54 MW). The plotted responses are shown in Appendix D. Again, loadshed in lieu of spin is not used in the GVEA system. The load shedding responses for each case are given in Table 3-2.

A 15 MW battery is able to reduce CEA load shedding (from the no battery case) only if a 0.5% droop is used. Increasing the battery size to 20 MW will reduce CEA load shedding from 23 to 17 MW, and this reduction is not sensitive to the droop used on the battery. However, a 25 MW battery is needed to prevent load shedding on the CEA system. This larger battery also eliminates load shedding in the Fairbanks area. A greater safety margin and smaller frequency deviation are obtained with a 30 MW battery.

In this scenario, except for the 15 MW battery case, a lower droop setting on the battery facility has no effect on load shedding. By analyzing the frequency plots though, one can see that smaller frequency deviations occur with a lower droop setting.

Table 3-2
LOADSHEDDING RESPONSES FOR SCENARIO 2 - AMOUNT OF LOAD SHED IN EACH UTILITY (MW)

BATTERY SIZE (MW)	DROOP SETTING(%)	CEA	AMLP	GVEA	FMUS
No Battery	No Battery	23	0	23	2.7
15	1.0	23	0	11.5	2.7
15	0.5	17	0	11.5	2.7
20	1.0	17	0	11.5	2.7
20	0.5	17	0	11.5	2.7
25	1.0	0	0	0	0
25	0.5	0	0	0	0
30	1.0	0	0	0	0
30	0.5	0	0	0	0

Scenario 3

Scenario 3 has the same generation condition as Scenario 2. However, in this scenario, the GVEA load shed in lieu of spin is activated. This increases the effective spinning reserve in GVEA and in the system by 9.2 MW. These relays are activated at 59.7 Hz and shed the required amount of load in two seconds. Cases are run with battery sizes of 15, 20 and 25 MW and droops of 0.5% and 1%. A "no battery" case is also considered. The Beluga #8 unit is tripped to initiate the frequency decay. The plotted responses are shown in Appendix E. Load shedding occurs only for the case without a battery as follows:

CEA = 17 MW AMLP = 0 MW

GVEA = 23 MW FMUS = 2.7 MW

The amount of load shed in the GVEA system is in addition to the 9.2 MW of load shed in lieu of spin. It is seen that a 15 MW battery will prevent load shedding in the CEA system. Either a 0.5% droop or a 1% droop will prevent load shedding in this scenario. In general, the cases with the lower droop setting have smaller transient frequency deviations. However, the final steady state frequency is approximately equal for either droop setting.

Cases were also run with the AMLP #6 and #7 units tripped. This represents the largest generation loss (95 MW) for the winter peak load condition. The plotted responses are also given in Appendix E. The load shedding responses are given in Table 3-3. If a 30 MW battery is used, load shedding in the CEA system is reduced to 23 MW. A 35 MW battery will eliminate load shedding.

Table 3-3
LOAD SHEDDING RESPONSES FOR SCENARIO 3 WITH THE AMLP UNITS TRIPPED - AMOUNT OF LOAD SHED IN EACH UTILITY (MW)

BATTERY SIZE (MW)	DROOP (%)	CEA	AMLP	GVEA	FMUS
15	1.0	23	0	11.5	2.7
20	1.0	23	0	11.5	2.7
25	1.0	23	0	8.8	2.7
30	1.0	23	0	8.8	2.7
35	1.0	0	0	8.8	2.7
40	1.0	0	0	8.8	2.7

Scenario 4

In Scenario 4, spinning reserve is reduced further from the Scenario 3 level by taking the Bernice Lake unit off-line. The spinning reserve in the CEA system without a battery is reduced to 5.3 MW. CEA is now deficient 39.6 MW of combustion turbine spinning reserve. The system as a whole is deficient by 44.3 MW. The following cases are run: battery size of 15, 20, 25 and 30 MW with droop set at 0.5% and 1%. Also a case is run without a battery. The Beluga #8 unit (54 MW) is tripped. The plotted responses are shown in Appendix F. The load shedding responses of the system for each battery size are given in Table 3-4.

With a 20 MW battery and a 0.5% droop setting, 17 MW of load shedding occurs in the CEA system. With a 25 MW battery, CEA sheds no load. Thus, 25 MW is the minimum size required to prevent load shedding in the CEA system under this scenario.

In previous scenarios, a droop setting of 0.5% was marginally superior to the 1% droop setting. However, in this scenario, the 0.5% droop setting causes a greater amount of load shedding in the CEA system than if a 1% droop is used (for the case with a 20 MW battery.) A 20 MW battery with a 0.5% droop delays load shed in lieu of spin in the GVEA system. This results in the load shedding relays on the CEA system operating. Therefore, a 1% droop setting is suggested for the battery controller. This scenario is also run with AMLP Units #6 and 7, (95 MW) tripped.

The plotted responses are also given in Appendix E. The load shedding responses are given in Table 3-4. For this large generation loss, even a 40 or 50 MW battery cannot prevent load shedding in the CEA system. However, the amount of load shedding can be reduced. From Table 3-4, it can be seen that a 30 MW battery allows 62.5 MW of load shedding, whereas a 40 MW battery reduces load shedding to 23 MW. Even though a 40 MW battery may not be feasible due to economic constraints, a 10 MW change in battery size can reduce load shedding considerably.

Table 3-4
LOAD SHEDDING RESPONSES FOR SCENARIO 4 - AMOUNT OF LOAD SHED IN EACH UTILITY (MW)

BATTERY SIZE (MW)	DROOP (%)	CEA	AMLP	GVEA	FMUS
		54 MW GENERATION LOSS			
No Battery	No Battery	23	0	27.4	2.7
15	1.0	23	0	8.8	2.7
15	0.5	23	0	8.8	2.7
20	1.0	0	0	7	2.7
20	0.5	17	0	8.8	2.7
25	1.0	0	0	7	2.7
25	0.5	0	0	8.8	2.7
30	1.0	0	0	0	0
30	0.5	0	0	0	0
		95 MW GENERATION LOSS			
20	1.0	62.5	11.8	30.1	2.7
30	1.0	62.5	0	11.5	2.7
40	1.0	23	0	30.1	2.7
50	1.0	23	0	8.8	2.7

Summer Normal Load

The summer normal load scenarios studied are outlined in Table 3-1. Under the summer normal load condition, the effectiveness of the battery is analyzed by introducing a disturbance consisting of the loss of the largest "unit", the AMLP Unit #6 and #7 combined cycle pair at 50 MW total output. This provides a comparable generation loss to the one simulated for the winter load condition (54 MW). However, AMLP #7 is also carrying 34 MW of the 95 MW of spin, so the system spin is reduced when this unit is tripped.

The composition and amount of the spinning reserve in the system is changed in each of the three scenarios. In all summer load scenarios, load shedding in lieu of spin is utilized in the GVEA system. Also, the battery droop setting in all three scenarios is 1%. The plotted responses for each scenario are given in Appendix G. The load shedding responses are given in Table 3-5.

Scenario 5

In Scenario 5, Beluga units #1 and #2 are on-line. They operate primarily to provide the necessary combustion turbine spinning reserve. Cases are run without a battery and with battery sizes of 15, 20 and 25 MW. In the case without a battery, all of the spinning reserve comes from the combustion turbines. The spinning reserve is at least as large as the largest generation loss, but load shedding is not prevented.

From Table 3-5, for the case without a battery, the CEA system sheds 19 MW of load. With a 15 MW battery, load shedding is reduced to 5.1 MW in the CEA system. A 20 MW battery is of sufficient size to eliminate all load shedding in the Railbelt system.

Scenario 6

For Scenario 6, Beluga #2, is removed. This effectively reduces spinning reserve by 15 MW. The system inertia in this scenario is also smaller than that of Scenario 5 due to the removal of this machine. Cases are run with no battery and with battery sizes of 15, 20 and 25 MW.

When no battery is used, 19 MW of load shedding occurs in the CEA system. Adding a 15 MW battery decreases load shedding to 7 MW in the CEA system. With a 20 MW battery, load shedding is eliminated in the entire Railbelt system.

By comparing the results of Scenarios 5 and 6, the effectiveness of battery spinning reserve vs. combustion turbine spinning reserve can be observed. The combustion turbine is replaced with a 15 MW battery (Scenario 5 without a battery vs. Scenario 6 with a 15 MW battery) and load shedding is limited to 7 MW in the CEA system. This reduction in load shedding occurs even though the total amount of spinning reserve has not changed and the system inertia is reduced.

Scenario 7

For Scenario 7, Beluga #1 and #2 are removed. This effectively reduces the spinning reserve in the Railbelt system by 31 MW. The system inertia is also reduced due to the removal of the two machines. Cases are run with no battery and with battery sizes of 15, 20 and 25 MW.

In the case with no battery, 19 MW of load is shed in the CEA system. By the addition of a 15 or 20 MW battery, load shedding is reduced to 7 MW in the CEA system. Load shedding is eliminated from the Railbelt system if a 25 MW battery is used.

By comparing the results of Scenarios 5 and 7, (Scenario 5 without a battery vs. Scenario 7 with a 15 MW battery) the effectiveness of replacing combustion turbine spin with battery spin can again be observed. It is seen that by replacing Beluga #1 and #2 with a 15 MW battery, load shedding is reduced from 19 to 7 MW in the CEA system. This occurs even though the total spinning reserve is reduced by 16 MW and the system inertia is also reduced.

By replacing Beluga #1 and 2 with a 25 MW battery, (Scenario 5 without a battery vs. Scenario 7 with a 25 MW battery) load shedding in the CEA system is eliminated. This is the case even though the total spinning reserve has been reduced by 5 MW and the total system inertia is smaller.

Table 3-5
LOAD SHEDDING RESPONSES FOR SCENARIOS 5, 6 AND 7 - AMOUNT OF LOAD SHED IN EACH UTILITY (MW) IN ADDITION TO LOAD SHED IN LIEU OF SPIN

	BATTERY SIZE (MW)	CEA	AMLP	GVEA	FMUS
SCENARIO 5	0	19	5.1	10.9	3.1
	15	5.1	0	4.1	1.2
	20	0	0	0	0
	25	0	0	0	0
SCENARIO 6	0	19	5.1	10.9	3.1
	15	7	0	4.1	1.2
	20	0	0	4.1	1.2
	25	0	0	0	0
SCENARIO 7	0	19	5.1	10.9	3.1
	15	7	0	10.9	3.1
	20	7	0	10.9	1.2
	25	0	0	0	0

4

T&D BENEFITS

CEA provided information about its long-range plans and about specific projects where a battery storage facility might play a significant T&D role. After review of the CEA long range plan information, it is believed that the CEA system could recognize some very significant T&D benefits from the applications of batteries. These T&D benefits combined with the spinning reserve and reduced load shedding benefits may help justify the application of batteries on the CEA system. The T&D benefits may also help justify the application of more battery capacity than can be economically supported by just the spinning reserve and reduced load shedding benefits.

The following subsections discuss some specific T&D projects on the CEA system where battery facilities may provide some significant benefits. It is suggested that these projects be evaluated more thoroughly to quantify the economics of battery facilities for each of these projects.

HUFFMAN SUBSTATION

The existing Huffman 34.5/12.5 kV Substation serves a significant portion of load in the southeast Anchorage area (see Hillside item below). This substation and the 34.5 kV system which feeds it are heavily loaded. The 34.5 kV system feeding this substation does not have adequate reserve margin to provide adequate service to this substation under single contingency conditions. Two 138 kV transmission lines and a 138/34.5 kV transformer at Huffman are proposed to provide support to the 34.5 kV system and the underlying distribution network.

A battery facility at Huffman at the 12.5 kV level could provide several benefits. It could provide voltage support under normal and single contingency conditions which would extend the usefulness of the existing 34.5 kV system thus deferring the need for the 138/34.5 kV transformer. Further, it could reduce the var loading on the Huffman load transformer thus increasing its ability to serve area loads. Although the 138 kV feed into Huffman would eventually be required for termination of the second Kenai intertie, a battery facility at Huffman may make it feasible to minimize 138 kV additions (e.g., eliminate or defer the need for the Huffman-University 138 kV line). A battery facility at Huffman used primarily for voltage support (i.e., vars, not real power support) would not undermine or erode the spinning reserve benefits provided by this battery. However, a battery facility at Huffman could provide real power service to loads following transformer failures until distribution switching could be performed.

HILLSIDE SUBSTATION

Loss of the Huffman transformer makes it impossible to maintain acceptable distribution voltages in the perimeter areas now served from the Huffman substation. The Hillside 34.5/12.5 kV substation (fed via a 34.5 kV line from Huffman) has been proposed to shift load from Huffman. Upgrading of an existing distribution feeder between Huffman and Hillside via an underbuild on the 34.5 kV line is proposed to facilitate back-up during transformer failures at either substation.

The Hillside substation has been built, but the 34.5 kV feed to it has been delayed due opposition by area residents. This has necessitated the use of a 34.5 kV cable circuit instead of an overhead line. This eliminates the possibility of the distribution underbuild to replace the existing distribution feeder. Further, the public opposition may circumvent the possibility of rebuilding the existing distribution feeder as well as constructing a second 34.5 kV feed into the Hillside substation. This may leave Hillside with a single 34.5 kV feed and minimal back up capability via the distribution system.

A battery facility at Hillside and located at the 12.5 kV level could provide two distinct benefits. First, the voltage support provided by a battery may make it feasible to back up the Hillside loads from Huffman over the existing distribution feeder. With a battery facility also at Huffman, the reverse situation may also be true. Thus, battery facilities at Hillside along with Huffman could eliminate or reduce the necessity of rebuilding or replacing the existing Huffman-Hillside distribution feeder. Further, a battery at Hillside may also defer or eliminate the need to build the second 34.5 kV feed into Hillside. As with the battery suggested for Huffman, a battery facility at Hillside would primarily play a var support role thus not undermining the potential spinning reserve benefits. However, it could provide real power support during transformer outages until distribution switching is performed to restore connection to the system.

GIRDWOOD, INDIAN AND PORTAGE SUBSTATIONS

These substations are taps off of the University-Daves Creek 115 kV line. Even with the presently proposed additions at these locations, service to Indian, Girdwood and Portage loads will be interrupted during outage of the 115 kV line.

Growing loads associated with the ski resort will result in the Girdwood transformer becoming overloaded. A second transformer at Girdwood is proposed, but requires rebuild of the substation. A 25 kV distribution connection between Girdwood and Indian is also proposed. With the proposed additions, Girdwood can back up the Indian loads, but Indian can provide only marginal back up to Girdwood even with the proposed single-phase transformer and regulator additions at Indian.[1] The Portage substation is proposed for conversion from 12.5 kV

1. The Girdwood and Indian distribution systems presently are not in phase. Hot transfer of loads, even with the proposed feeder, will not be possible unless the transformer addition at Indian also corrects the phasing problem.

to 25 kV. Four single phase transformers and regulators are proposed as part of this conversion. Under the present plan, the proposed Portage changes have no impact on Girdwood.

A battery facility at Girdwood could defer the transformer capacity addition at Girdwood. A battery of sufficient size could reduce the var loading and could be used for peak shaving to extend the useful capability of the Girdwood transformer. Further, it could provide service to the important Girdwood loads during outages of the University-Daves Creek 115 kV line or the Girdwood transformer. The battery could be sized to provide load service time sufficient to do sectionalizing of the 115 kV line or to transport portable generation to Girdwood. A battery at Girdwood could also possibly defer the need for the distribution feeder to Indian.

Alternatively, a battery facility at Girdwood could enhance the usability of the proposed Girdwood-Indian distribution feeder if it is built. Further, it would make feasible the installation of a large, 3-phase LTC transformer at Indian versus the medium sized single phase transformers and regulators now proposed. Thus, the Indian substation via the proposed feeder would be able to back up all of the Girdwood load with battery facility support at Girdwood. Replacing the transformers at Indian with a large unit would eliminate the need to rebuild the Girdwood substation.

In the long range, a battery facility at Girdwood would also make feasible the use of a larger transformer at Girdwood and the interconnection of the Girdwood and Portage distribution systems. With a 25 kV circuit between Girdwood and Portage (in addition to the Girdwood-Indian tie) and sufficient transformer capacity at Portage (e.g., 14 MVA), a battery facility at Girdwood would provide the ability to back up the loss of a 15/20/25 MVA transformer at Girdwood by using both the Indian and Portage sources. In addition, a Girdwood-Portage tie would provide the necessary back up to the Portage loads. Thus, a battery at Girdwood would facilitate the full interconnection of the Indian, Girdwood and Portage distribution systems, support full back up of Girdwood load from the adjacent substations, and allow the use of single, large, 3-phase LTC transformers at Indian, Girdwood and Portage (e.g., 14, 25 and 14 MVA, respectively). This would minimize (physical) substation expansions at any of these locations which would otherwise be required if multiple transformers are used of if single-phase transformers and regulators are used.

HOPE

The Village of Hope if fed via a 19 mile long, single-phase line from a simple tap substation on the University-Daves Creek 115 kV line. Due to growing loads at Hope, voltage drop is becoming a problem. In-line voltage regulators for voltage improvement are the proposed near-term solution. The long-term solution is to replace the existing line with a 3-phase line and completely rebuild the Hope 115 kV substation. Hope would still have only a single feed after these proposed additions.

A battery facility at the Village of Hope would provide some significant benefits. First, it would provide the necessary voltage support to extend the usefulness of the existing single-phase feed. This would avoid the cost of the regulators and the longer-term costs associated with the line and substation rebuild. Second, a battery facility could provide service security to Hope during outages of the 115 kV line or the radial distribution feed. The battery could be sized to provide 4-8 hour back up capability. This should be sufficient to allow most line repairs to be effected or to bring in portable generation equipment.

A further benefit of a battery facility is that it could provide 3-phase service to Hope from the existing single-phase feeder. The single-phase line could power a charger for the battery facility, and the battery power conversion equipment could produce three-phase power for the village. Thus, a battery facility could essentially eliminate the need to perform the proposed conversions, and it would provide reliability benefits which would not be provided by the proposed conversions.

5

COST/BENEFIT ANALYSIS

In this section the dollar value of the benefits described in the previous three sections is compared to the cost of installing batteries. Following common industry practice, costs and benefits are expressed in 1990 dollars per kilowatt of capacity or dollars per kilowatt-year of capacity; the latter is a current dollar levelized cost over the battery unit's life.

BATTERY CAPITAL COSTS

Because there are currently only a handful of utility battery installations in operation or planned, there are no commonly accepted estimates for battery storage system costs. In addition, costs are very dependent not only on power capacity and storage capacity, but also on frequency with which the battery is to be charged and discharged and the depth of discharge.

The cost estimates used here are from EPRI's Technical Assessment Guide (TAG). They have already been described in Section 1 of this document. Adjusted for inflation, the total cost is $703/kW for a 3-hour battery and $943/kW for a 5-hour battery, including land cost. The TAG does not provide a cost estimate for a one-half or 1-hour battery that could provide spinning reserve but would have minimal energy capacity; we estimate that such a battery would cost $350/kW. This is based on the EPRI TAG numbers, but reducing the storage component of the 3-hour battery cost by two-thirds.

Using a fixed charge rate of 13.7%[1] to convert overnight capital costs to current dollar levelized annual battery costs yields the following:

Size (hours)	Levelized Capital Cost ($/kW-year)
1	$49
3	$97

1. Suggested by CEA for equipment with a 30-year life.

The cost estimates in the EPRI TAG do not include cell replacement during the life of the battery system; the individual cells do not last as long as the entire system. Depending on the number of cycles per year that the battery is operated, cell replacement costs could add on the order of $100/kW to the battery cost, or about $15/kW-year; for batteries operated primarily to provide spinning reserve, cell replacement costs should be much smaller. In addition, the operating and maintenance (O&M) costs for the battery system should be included in a detailed analysis; they are ignored in this screening-level analysis.

CAPACITY VALUE OF BATTERY

Another potential benefit or savings that can be attributed to batteries, not discussed in the previous sections, results from the battery's contribution to total system generating capacity. The addition of battery capacity to a utility system frequently allows a reduction in investment in other new generation. Since the Anchorage area is expected to face a generation capacity shortage around 1995,[2] battery capacity may be able to replace some of the new generation capacity that will be required. However, a battery with only one hour of storage may not merit the same capacity value of a unit such as a combustion turbine. A capacity credit of $67/kW-year,[3] based on the cost of a combustion turbine, is an upper bound for the capacity value of a battery.

COMPARING BENEFITS TO COSTS

The annual costs just described can now be compared to the benefits estimated in Sections 2, 3, and 4. Recall that, as described in Section 2, there were no load-leveling benefits on the CEA system. This resulted from the relative flatness of the hourly system marginal costs (system lambda).

Because there are no load-leveling benefits, the battery system considered here would have minimal storage capacity and would be used only to provide spinning reserve. In order to maximize the net operating benefits, enough battery capacity must be added to allow the decommitment of one of the marginal units; this would require 20 to 25 MW of battery capacity. As described in Section 2, some of the smaller combustion turbines are frequently operated at loadings far from their most efficient ones in order to provide spinning reserve. Addition of battery storage to the CEA system would allow decommitting these smaller units, providing substantial dynamic operating benefits. Because of the limitations imposed by the screening nature of this analysis, it was difficult to determine precise, consistent estimates of these benefits, However, a value of $40 to $70 per kW-year, levelized in current dollars, appears appropriate.

2. *Economic Feasibility of the Proposed 138 kV Transmission Lines in the Railbelt*, prepared by Decision Focus Incorporated for Railbelt Electric Utilities, December 1989.

3. $490 per kW combustion turbine capital cost times current dollar levelized fixed charge rate of 13.7%.

Section 3 described how the addition of battery storage to the CEA system could reduce load shedding. We can estimate the dollar value of this reduced load shedding as follows:

1. Unserved energy in the Anchorage area has been about 655 MWh/year.[4]

2. The value of unserved energy is about $5/kWh.[5]

3. Assume that the addition of a 20 MW battery to the system reduces unserved energy by 5-10 percent.

Combining these assumptions yields a reduced load shedding benefit of $8 to $16 per kW of battery capacity per year.[6]

Time and budget constraints, together with the direction taken early in the project, made it impossible to calculate potential T&D investment deferral benefits in any detail. However, based on a qualitative analysis and detailed analyses for other utilities, potential T&D benefits of $20 to $200 per kW of battery capacity would appear reasonable. Using the same levelized fixed charge rate used above for levelizing battery capital costs yields a T&D benefit of $3 to $27 per kW of battery capacity per year.

Benefits in all categories are summarized in Table 5-1. In a screening level analysis such as this, it is not possible to be more precise. For example, the T&D benefits are very site-specific and can not be precisely calculated without identifying sites for battery installations and then carrying out detailed T&D expansion plans with and without batteries.

Table 5-1
BENEFITS SUMMARY FOR CEA SYSTEM

Category	Annual Benefit ($/kW-year)
Capacity	30-70
Generation	40-70
Reduced Load Shedding	8-16
T&D	3-27
TOTAL	81-183

4. *Economic Feasibility of the Proposed 138 kV Transmission Lines in the Railbelt*, prepared by Decision Focus Incorporated for Railbelt Electric Utilities, December 1989.

5. Ibid.

6. 655 MWh/year x 1000 kWh/MWh x $5/kWh x 5-10% ÷ 20,000 kW = $8-16/kW-year.

Comparing total benefits to the battery costs, which are roughly \$50 to \$60 per kW-year for a 1-hour battery, indicates that batteries may be quite economic on the CEA system.

6

CONCLUSIONS AND RECOMMENDATIONS

In this study several types of benefits that would occur from the addition of batteries to the CEA system were calculated: generation (load-leveling, dynamic operating, and environmental) and transmission and distribution. These benefits were also compared to the costs of adding batteries. The results suggest that savings in dynamic operating costs and T&D costs may justify the addition of batteries to the system.

GENERATION BENEFITS

Generation benefits were calculated for 18 days: in each of three years (1994, 1996, and 2000), one weekday and one weekend day for each season (with spring and fall combined), using data from CEA MAINPLAN runs. The benefits were calculated for five gas-fired combustion turbine units whose operation is most likely to be affected by the addition of batteries to the system. The primary emphasis was on provision of spinning reserve with a one-hour battery.

Load-Leveling Benefits

Because the marginal units on the CEA system are gas-fired combustion turbines (the Beluga and Bernice units) for all hours, the system marginal energy costs do not differ much between on-peak and off-peak hours. Coupled with the assumed battery efficiency of around 80 percent, this means that no load-leveling savings could be achieved on the CEA system.

Dynamic Operating Benefits

A large portion of the operating costs of power plants results from fluctuating loads. These costs are called dynamic operating costs, and include such things as startups, minimum loading, load following, and ramping. Technologies such as batteries that can reduce these costs are said to provide dynamic operating benefits.

For each of the 18 days the potential reduction in load following, minimum loading, startup, and spinning reserve costs was calculated for each of the five units. The most cost-effective unit for decommitment was identified on each day. By accounting for the relative occurrence of each of the "day types" during the year, an annual savings was calculated. The biggest component of the savings is from reductions in minimum loading costs. Averaging out the effect of load growth and accounting for inflation and increases in natural gas prices, this is equivalent to an annual savings of about $50, levelized in current dollars, per kilowatt per year. The savings may increase in the future as load growth forces increasing utilization of less economic units. The annual savings were about $18/kW-year in 1994, $55/kW-year in 1996, and $25/kW-year in 2000. The fluctuations arise from increases in natural gas prices and load growth. Savings go up as gas prices increase, and can go up or down as load grows.

Environmental Benefits

Atmospheric emissions from fossil-fuel combustion in generation units are not much of a concern in the Railbelt at this time. Should they become a concern, the capability of batteries to reduce or otherwise modify emissions should be quantified. Similarly, if land use is a significant concern, the potential for batteries to eliminate or defer new transmission lines should be considered.

REDUCED LOAD SHEDDING BENEFITS

As described in Section 2, addition of battery storage to the CEA system would be effective in reducing load shedding. The amount of the reduction would depend on the size of the battery. A very approximate calculation indicates that the value of the reduced load shedding could be $8 to $16 per kW of battery capacity per year.

TRANSMISSION AND DISTRIBUTION BENEFITS

Current CEA transmission and distribution facility expansion plans were reviewed to identify T&D investments that might be avoided or deferred as a result of adding battery storage to the CEA system. Several such investments were identified. Based on a qualitative review of these investments and comparison with more detailed analyses for other utilities, potential T&D benefits of $20 to $200 per kW of battery capacity appear reasonable. This is equivalent to a T&D benefit of $3 to $27 per kW of battery capacity per year.

COST/BENEFIT ANALYSIS

Summing the capacity, generation, load shedding, and T&D benefits yields levelized current-dollar savings of $81 to $183/kW-year, compared to a levelized current-dollar cost of $50 to $60/kW-year. These values suggest that batteries would be a cost-effective addition to the CEA system.

Some benefits may be mutually exclusive. The interactions between the various benefits, i.e., whether they are additive or mutually exclusive, depends on storage size, location, system load shapes, load shapes at individual substations and on individual transmission and distribution lines, how the system (including the battery) is operated, and on any equipment deferred as a result of adding batteries.

RECOMMENDATIONS

Based on the results of this screening-level study, it is recommended that CEA seriously consider the addition of battery storage to its system. A detailed study to verify the findings of this initial screening study and to calculate the benefits more precisely is recommended. Such a study should include the following aspects:

1. More detailed calculation of generation dynamic operating costs and benefits should be carried out, including examination of multiple weeks of system operation during each of a larger number of years than was considered here. Such calculation should fully account for changes in system operation as load grows, and should identify all possible operation savings, not only those that arise when a unit is completely decommitted.

2. More detailed T&D analysis should be carried out to verify the assumptions and findings discussed here.

3. Particular care should be paid to the interactions among the various benefits, to ensure that batteries are not being justified on the basis of benefits that may be mutually exclusive.

4. Comparative evaluation of the economics of battery storage with other capacity additions under consideration by CEA. Such detailed study would also allow a better assessment of the "optimum" battery size and the best time for adding the battery plant to the CEA system.

5. A broader perspective, which looks at the benefits of battery storage to the Railbelt utilities as a whole, should be considered. The broader perspective might show increased benefits, while there would be no change in battery costs. In particular, because of CEA's arrangements for selling economy energy to the Golden Valley Electric Association, the reduced spinning reserve costs made possible by batteries might be more valuable to one of the other Railbelt utilities than to CEA.

A

DAILY CEA SYSTEM LOAD SHAPES AND MARGINAL GENERATION COSTS

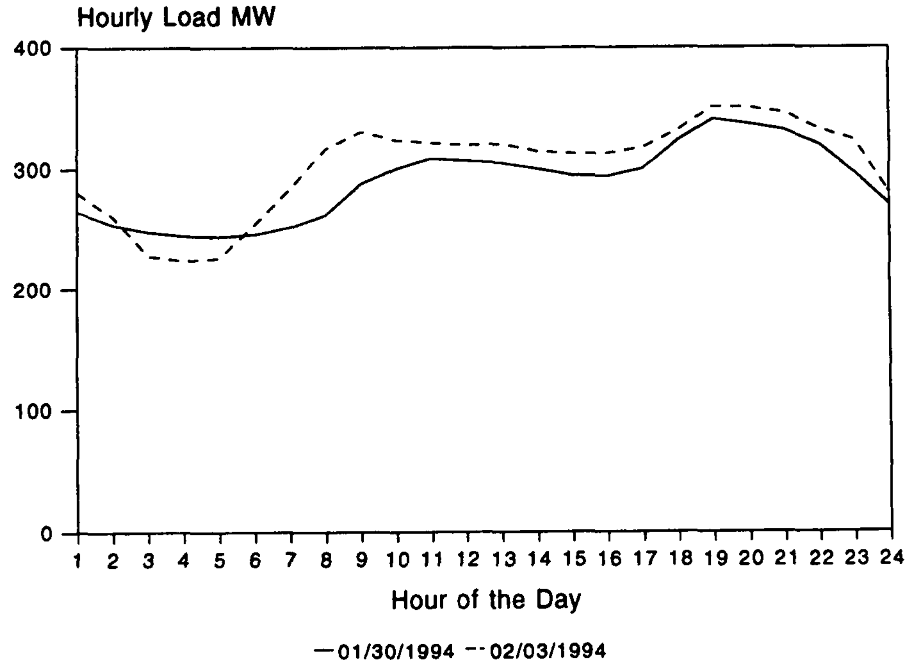


Figure A-1. Native Daily Load Shapes—Winter 1994

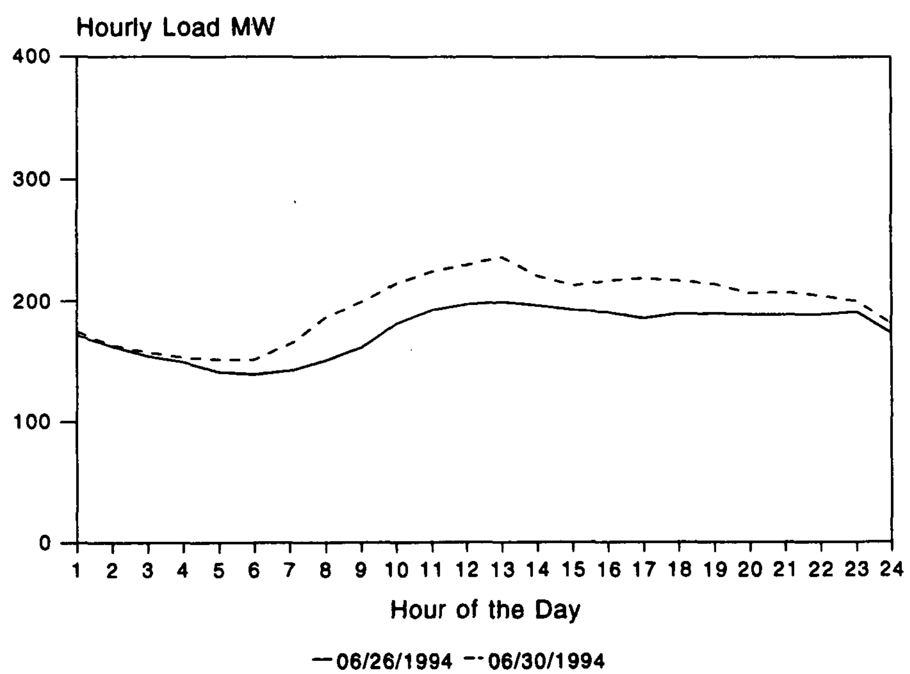


Figure A-2. Native Daily Load Shapes—Summer 1994

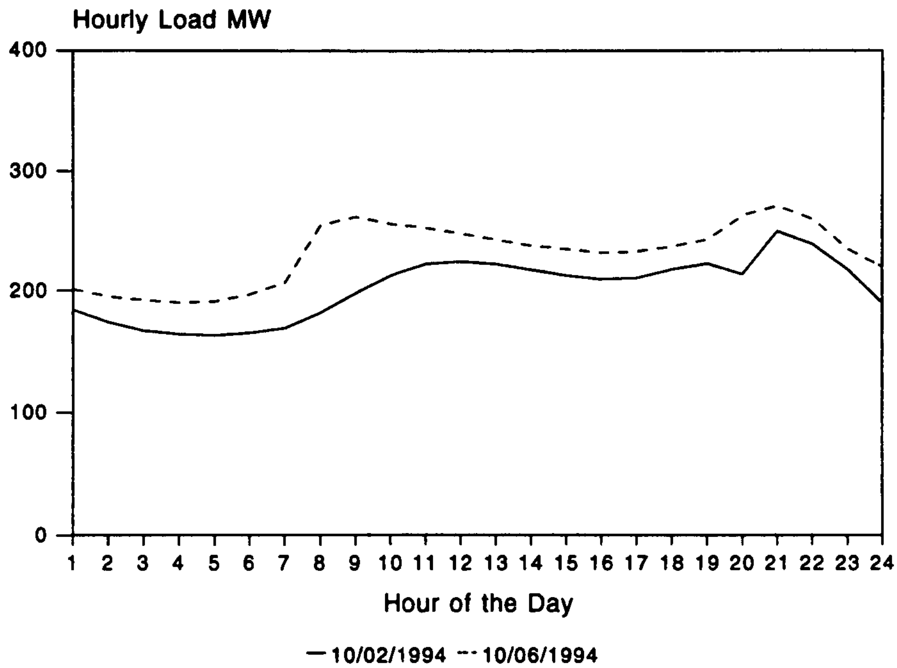


Figure A-3. Native Daily Load Shapes—Spring/Fall 1994

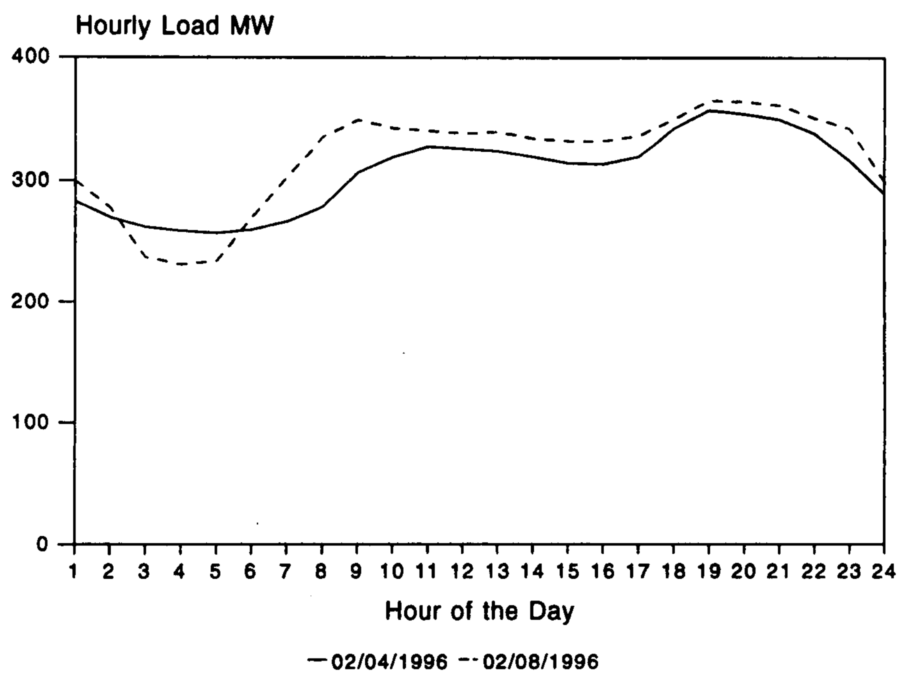


Figure A-4. Native Daily Load Shapes—Winter 1996

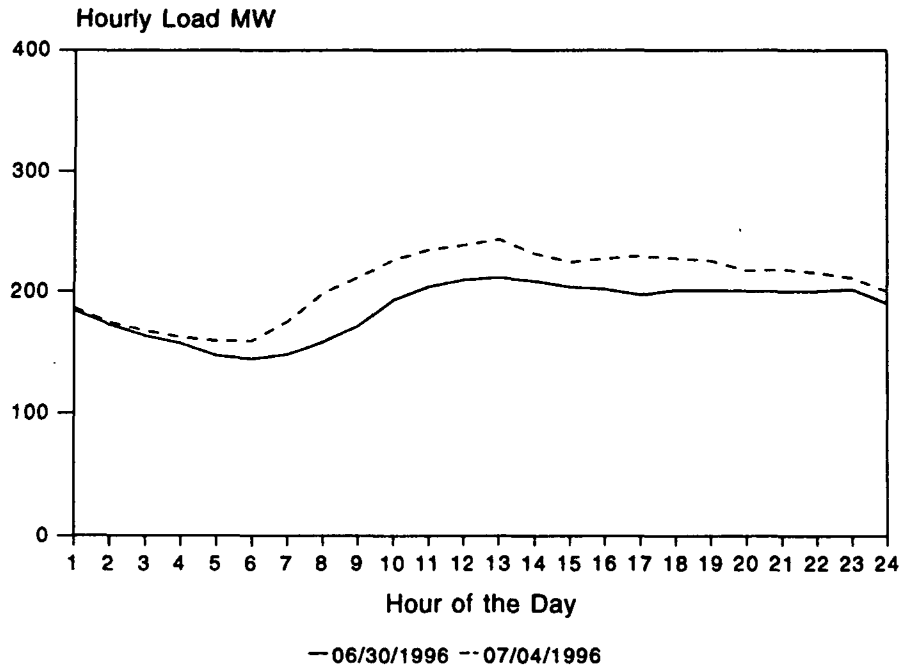


Figure A-5. Native Daily Load Shapes—Summer 1996

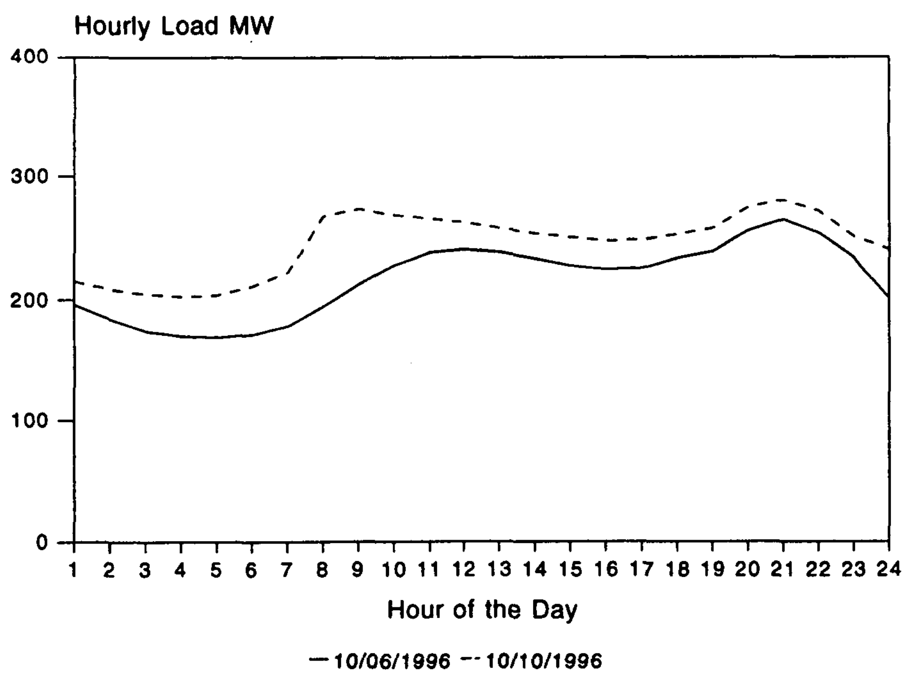


Figure A-6. Native Daily Load Shapes—Spring/Fall 1996

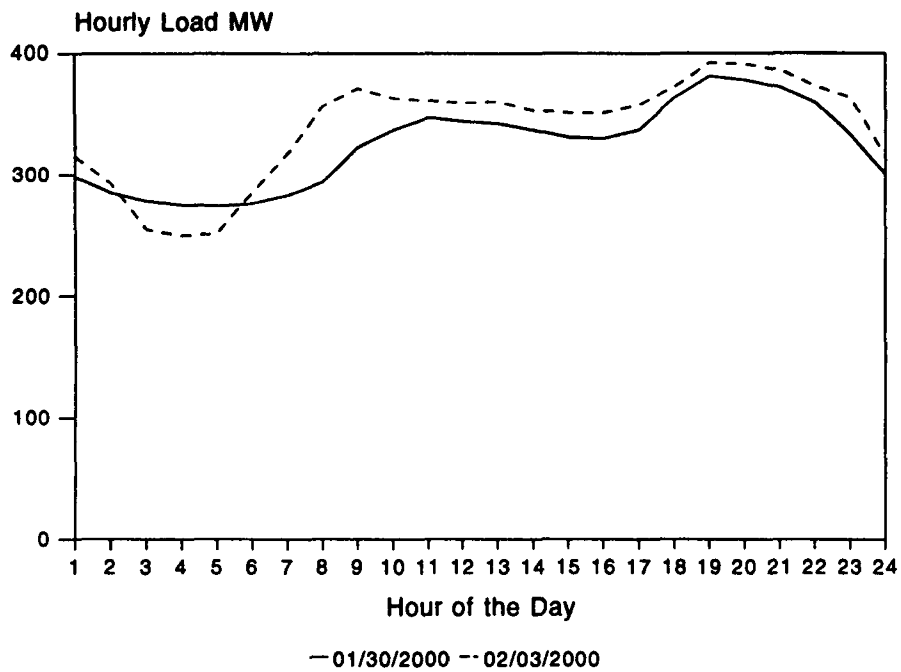


Figure A-7. Native Daily Load Shapes—Winter 2000

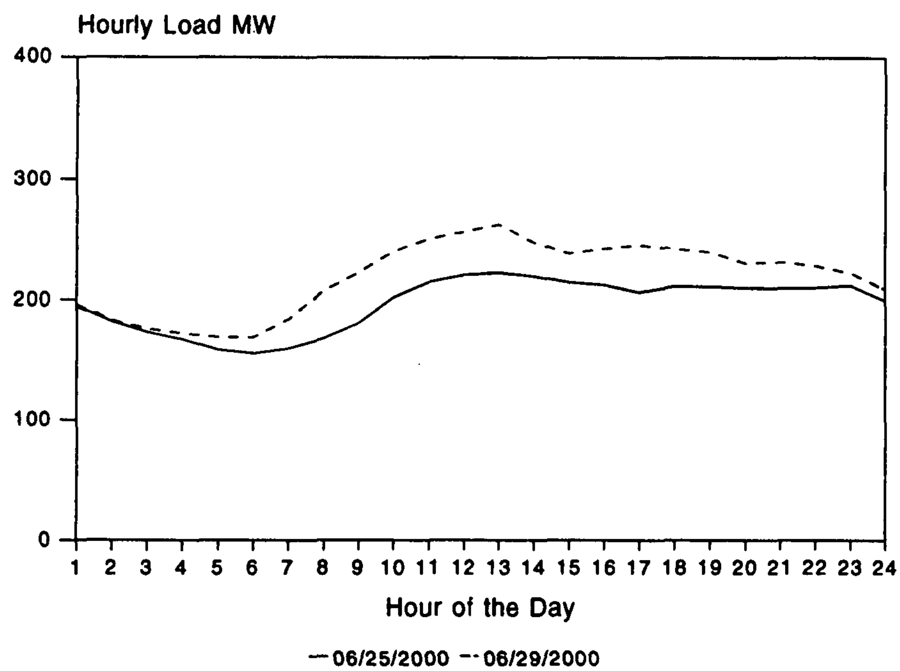


Figure A-8. Native Daily Load Shapes—Summer 2000

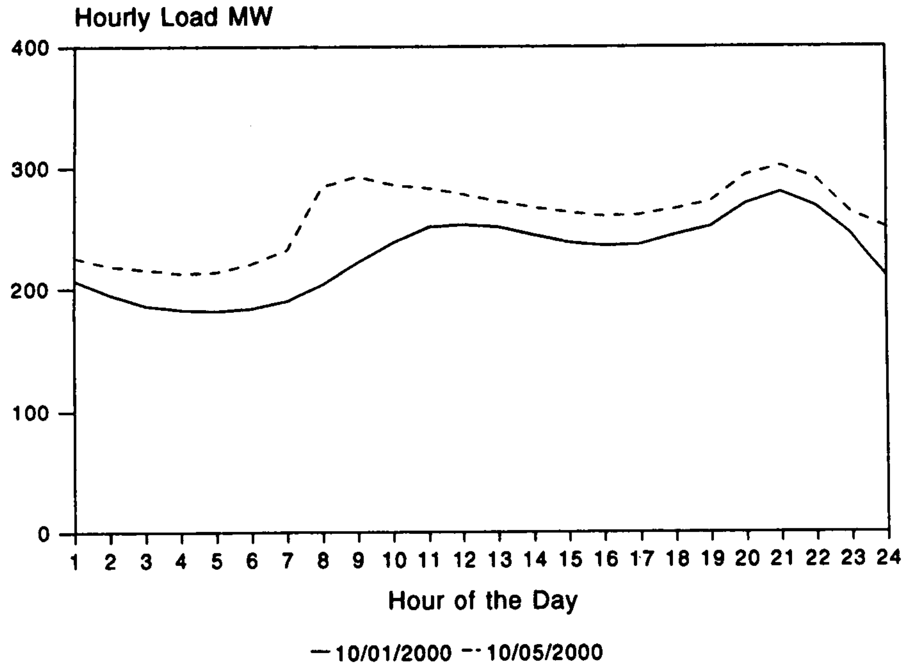


Figure A-9. Native Daily Load Shapes—Spring/Fall 2000

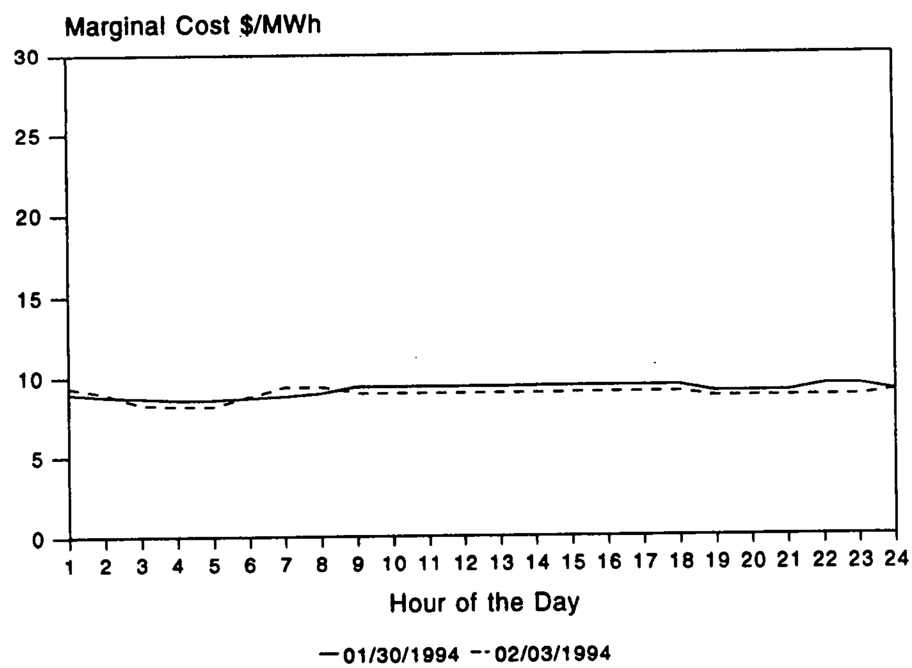


Figure A-10. System Marginal Cost—Winter 1994

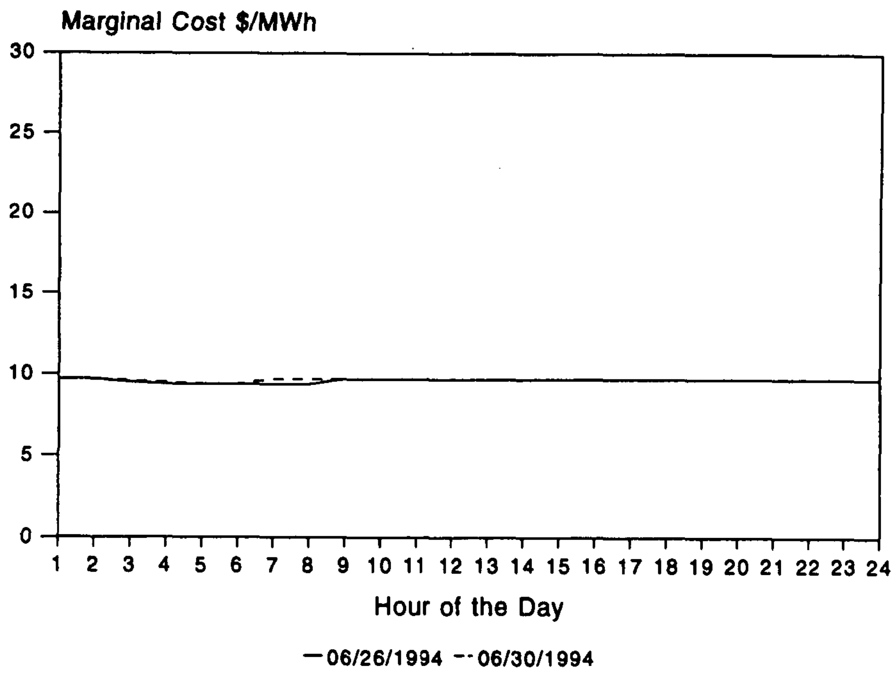


Figure A-11. System Marginal Cost—Summer 1994

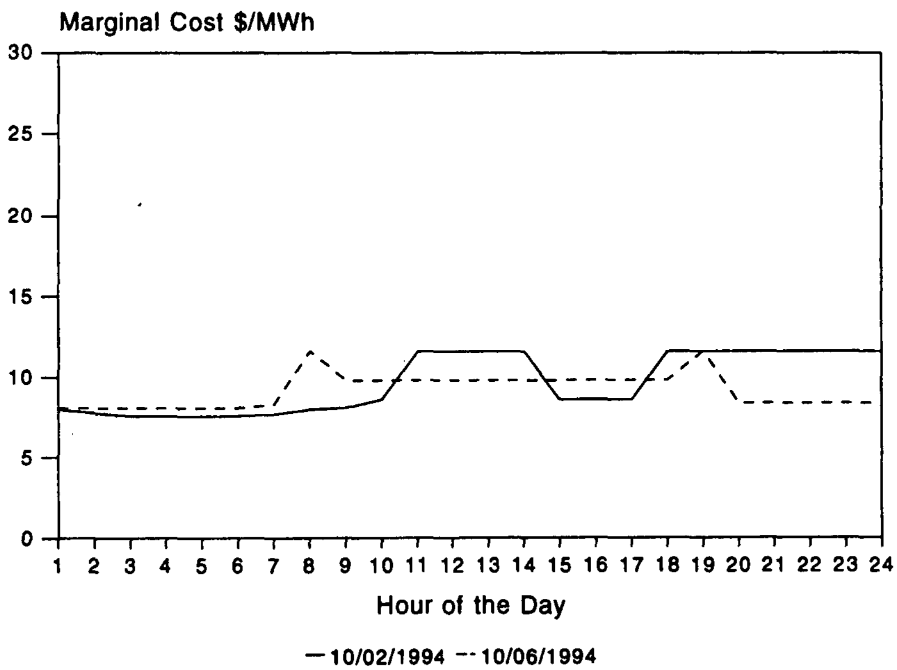


Figure A-12. System Marginal Cost—Spring/Fall 1994

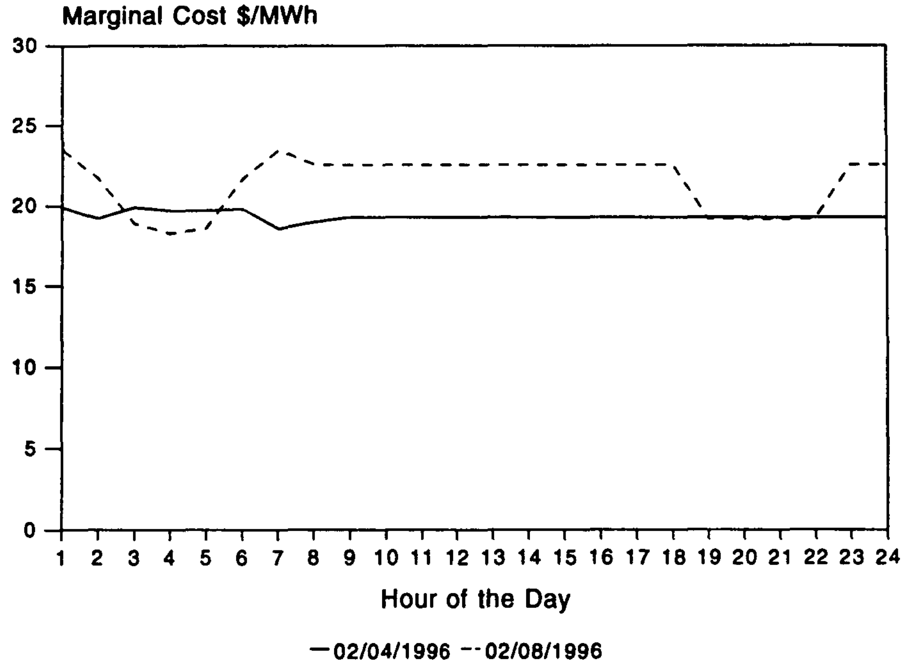


Figure A-13. System Marginal Cost—Winter 1996

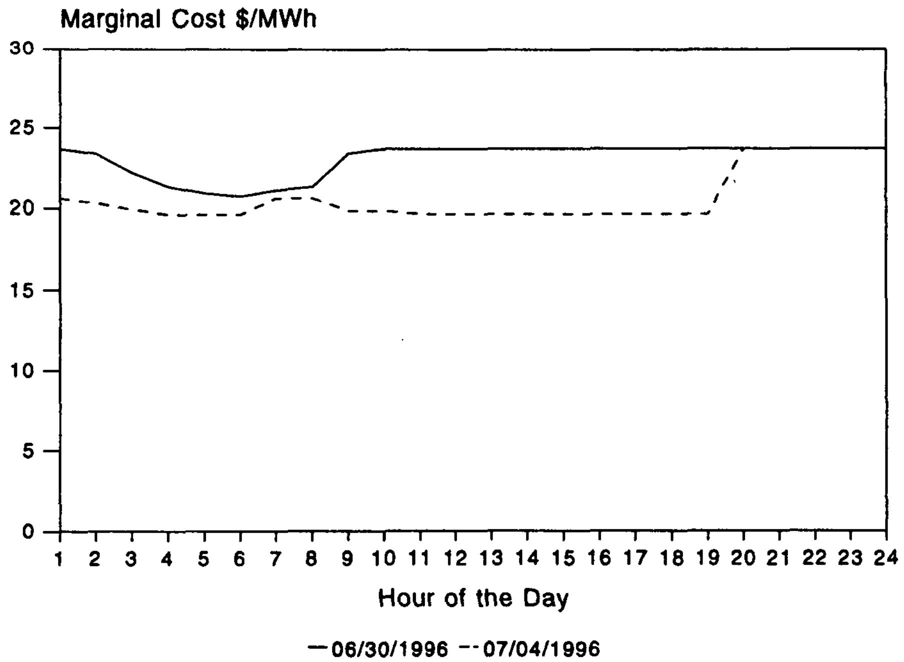


Figure A-14. System Marginal Cost—Summer 1996

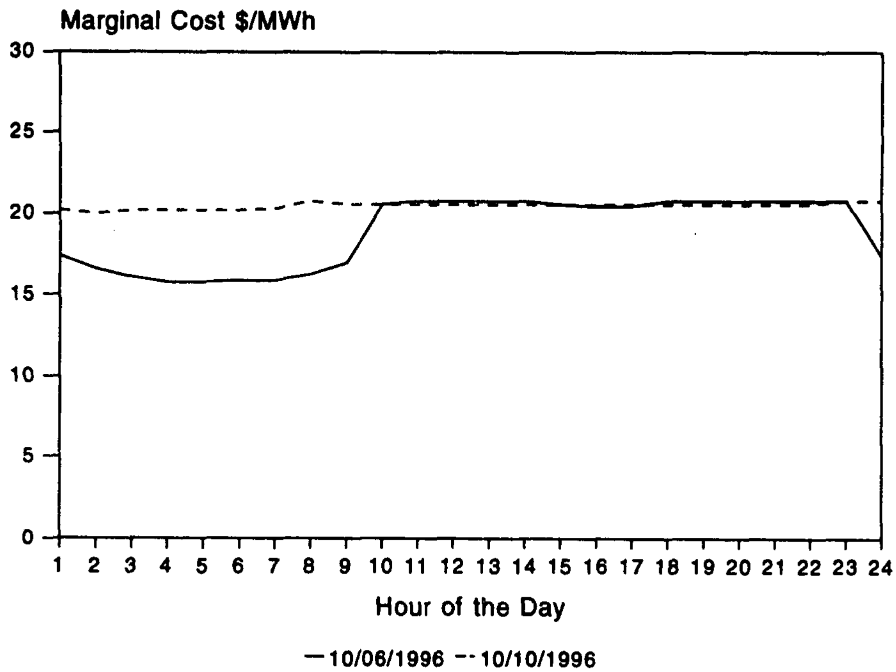


Figure A-15. System Marginal Cost—Spring/Fall 1996

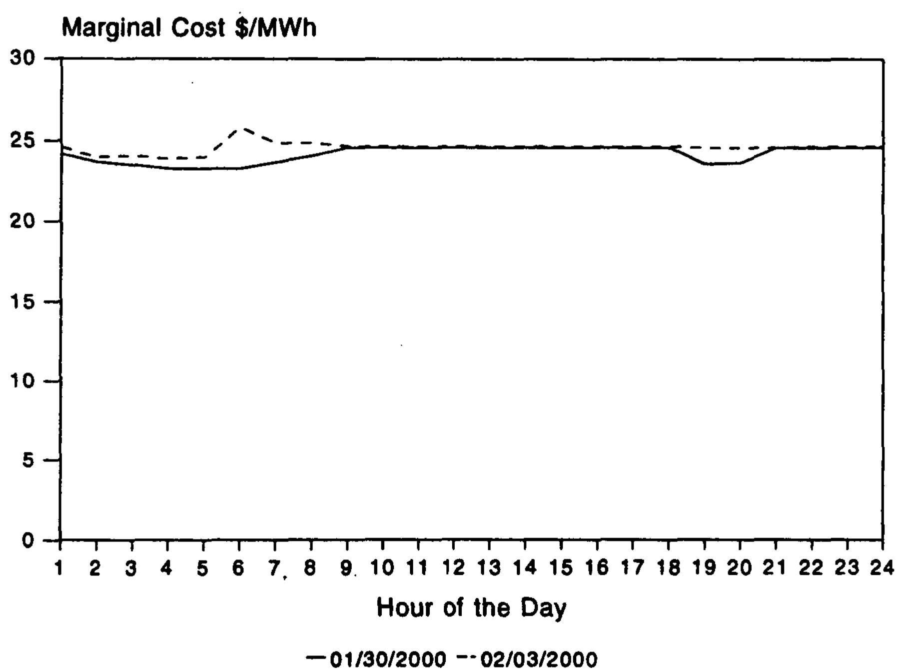


Figure A-16. System Marginal Cost—Winter 2000

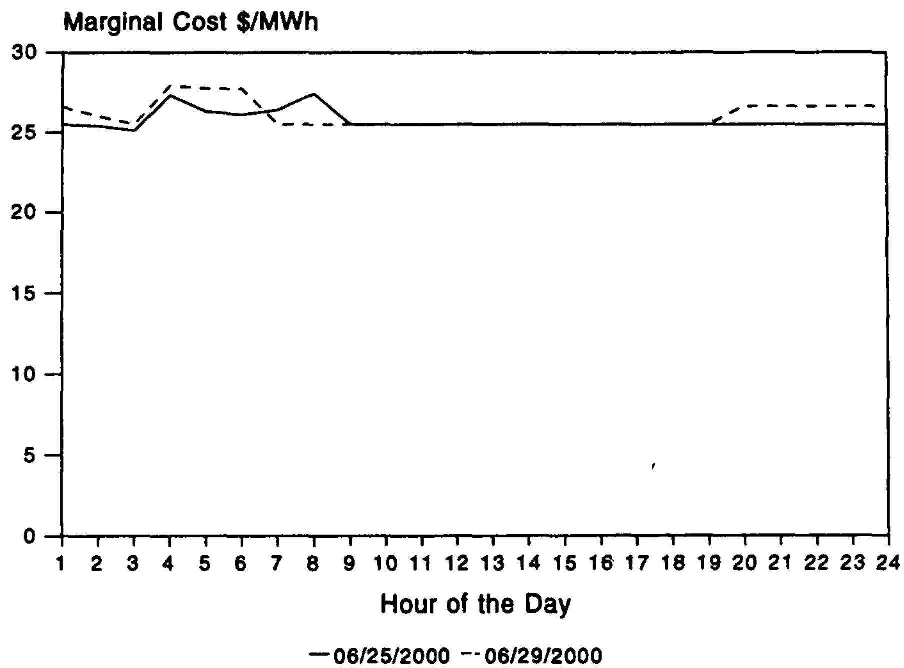


Figure A-17. System Marginal Cost—Summer 2000

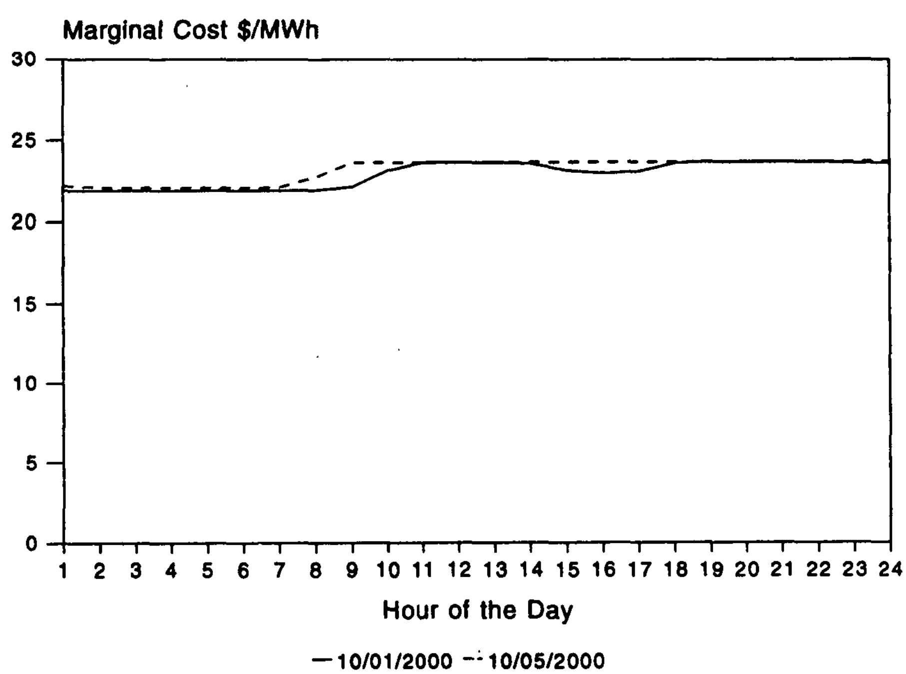


Figure A-18. System Marginal Cost—Spring/Fall 2000

B

GENERATION SCHEDULES FOR STABILITY ANALYSIS SCENARIOS

This appendix presents the generation schedule for each scenario studied in this report.

For the winter load case: Beluga #5, 6, 7 and 8, the Bradley and Eklutna units, Healy and Chena 5 are at their maximum capacity. North Pole is at 50 MW (60 MW capacity), AMLP Unit 7 is at 72 MW (85 MW capacity) and AMLP Unit 6 is at 23 MW.

Scenario 1: Beluga 3 at 55.7 MW, Bernice Lake at 10 MW, Cooper 1 & 2 at 13 MW and AMLP Unit 8 at 23.8 MW.

Scenario 2 & 3: Beluga 3 at 55.7 MW, Bernice Lake at 10 MW and Cooper 1 & 2 at 13 MW. In this scenario, AMLP Unit 8 is taken off line and its generation replaced with AMLP Unit 1 at 5MW (17 MW capacity) and AMLP Unit 5 at 18.8 MW (37 MW capacity).

Scenario 4: Bernice Lake taken off-line. Beluga 3 is therefore at 62.7 MW and Cooper #1 & #2 are at their maximum capacity of 16 MW. The AMLP units are as in Scenario 2 and 3.

For the summer load case: Beluga 6, Beluga 8 and Healy are at maximum capacity, Eklutna is at 7 MW (16 MW capacity), Chena 5 is at 12.5 MW (18 MW capacity), Bradley 1 & 2 are at 15 MW each, AMLP Unit #6 is at 12 MW, and AMLP Unit #7 is at 38 MW (72 MW capacity).

Scenario 5: Beluga 1 at 5 MW (15 MW capacity), Beluga 2 at 5 MW (16 MW capacity), and Beluga 3 at 31.6 MW.

Scenario 6: Beluga 1 at 5 MW (15 MW capacity), Beluga 2 off-line and Beluga 3 at 36.6 MW.

Scenario 7: Beluga 1 and 2 off-line and Beluga 3 at 41.6 MW.

PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E SUN, DEC 29 1991 13:13
1991 WINTER PEAK LOAD. NO BATTERY AT INTL. 34.5.
GOVERNORS DISABLED AT BELUGA 5,6,7, CHENA 5, HEALY. SCENARIO 1

GENERATOR SUMMARY:

BUS	NAME BSVLT	#MAC	TYP	MW	MVAR	QMAX	QMIN	VSCHED	VACTUAL	REM
3	BELUGA3G13.8	1	3	55.7	6.4	24.8	-12.4	1.0150	1.0150	
5	BELUGA5G13.8	1	2	59.0	5.6	33.0	-16.5	1.0150	1.0150	
6	BELUGA6G13.8	1	2	78.0	7.7	37.1	-11.1	1.0180	1.0180	
7	BELUGA7G13.8	1	2	75.0	5.3	37.1	-11.1	1.0150	1.0150	
8	BELUGA8G13.8	1	2	54.0	5.6	30.0	-15.0	1.0150	1.0150	
24	EKLUT 2G6.90	1	2	16.0	3.0	7.3	-2.2	1.0000	1.0000	
25	EKLUT 1G6.90	1	2	16.0	3.0	7.3	-2.2	1.0000	1.0000	
34	TEELAND 13.8	1	2	0.0	6.7	22.0	-22.0	1.0050	1.0050	15
67	BERN 3G 13.8	1	2	10.0	8.7	13.9	-6.9	1.0300	1.0300	
79	COOP1&2G4.20	2	2	13.0	3.4	14.7	-9.2	1.0300	1.0300	
121	FORT W. 12.4	4	2	7.5	1.7	5.4	-2.6	1.0500	1.0500	
201	GLDHLSVS13.8	1	-2	0.0	33.0	33.0	-5.0	1.0280	1.0199	202
210	N. POLE 13.8	2	2	50.0	7.7	34.8	-17.4	0.9860	0.9860	
213	CHENA 12.5	3	2	20.0	9.9	12.2	-4.0	1.0350	1.0350	
368	HEALYSVS12.0	1	2	0.0	7.1	22.0	-33.0	1.0220	1.0220	37
370	HEALY 1G13.8	1	2	25.0	3.1	15.5	-7.5	1.0140	1.0140	
501	BRADLY1G13.8	1	2	45.0	3.6	19.7	-19.7	1.0000	1.0000	
502	BRADLY2G13.8	1	2	45.0	3.7	19.7	-19.7	1.0000	1.0000	
601	PLNT2 6G13.8	1	2	23.0	12.2	20.5	-10.2	1.0200	1.0200	
602	PLNT2 7G13.8	1	2	72.0	32.2	49.7	-24.8	1.0000	1.0000	
603	PLNT2 8G13.8	1	-2	23.8	52.3	52.3	-26.1	1.0320	1.0292	
691	TESORO1G24.9	1	-2	4.1	1.5	1.5	1.5	1.0300	1.0235	
SUBSYSTEM TOTALS				692.1	223.5	513.4	-277.1	MVABASE=		1100.3

PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E SUN, DEC 29 1991 13:13
1991 WINTER PEAK LOAD. AMLP #8 IS OFF, AMLP #1 & #5 ARE ON. SCENARIO 2,3
NO BATTERY AT INTL 34.5KV.

GENERATOR SUMMARY:

BUS	NAME BSVLT	#MAC	TYP	MW	MVAR	QMAX	QMIN	VSCHED	VACTUAL	REM
3	BELUGA3G13.8	1	3	55.5	8.3	24.8	-12.4	1.0150	1.0150	
5	BELUGA5G13.8	1	2	59.0	7.0	33.0	-16.5	1.0150	1.0150	
6	BELUGA6G13.8	1	2	78.0	9.5	37.1	-11.1	1.0180	1.0180	
7	BELUGA7G13.8	1	2	75.0	7.4	37.1	-11.1	1.0150	1.0150	
8	BELUGA8G13.8	1	2	54.0	7.7	30.0	-15.0	1.0150	1.0150	
24	EKLUT 2G6.90	1	2	16.0	4.2	7.3	-2.2	1.0000	1.0000	
25	EKLUT 1G6.90	1	2	16.0	4.2	7.3	-2.2	1.0000	1.0000	
34	TEELAND 13.8	1	2	0.0	9.7	22.0	-22.0	1.0050	1.0050	15
67	BERN 3G 13.8	1	2	10.0	8.9	13.9	-6.9	1.0300	1.0300	
79	COOP1&2G4.20	2	2	13.0	3.7	14.7	-9.2	1.0300	1.0300	
121	FORT W. 12.4	4	2	7.5	1.7	5.4	-2.6	1.0500	1.0500	
201	GLDHLSVS13.8	1	-2	0.0	33.0	33.0	-5.0	1.0280	1.0199	202
210	N. POLE 13.8	2	2	50.0	7.7	34.8	-17.4	0.9860	0.9860	
213	CHENA 12.5	3	2	20.0	9.9	12.2	-4.0	1.0350	1.0350	
368	HEALYSVS12.0	1	2	0.0	7.1	22.0	-33.0	1.0220	1.0220	37
370	HEALY 1G13.8	1	2	25.0	3.1	15.5	-7.5	1.0140	1.0140	
501	BRADLY1G13.8	1	2	45.0	3.8	19.7	-19.7	1.0000	1.0000	
502	BRADLY2G13.8	1	2	45.0	3.9	19.7	-19.7	1.0000	1.0000	
600	PLNT2 5G13.8	1	-2	18.8	17.1	17.1	-8.5	1.0150	0.9965	
601	PLNT2 6G13.8	1	2	23.0	18.1	20.5	-10.2	1.0200	1.0200	
602	PLNT2 7G13.8	1	2	72.0	39.8	49.7	-24.8	1.0000	1.0000	
607	PLNT1 1G13.8	1	2	5.0	6.3	9.4	-4.7	1.0200	1.0200	
691	TESORO1G24.9	1	-2	4.1	1.5	1.5	1.5	1.0300	1.0227	
SUBSYSTEM TOTALS				691.9	223.7	487.6	-264.2	MVABASE=		1055.8

PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E SUN, DEC 29 1991 13:13
1991 WINTER PEAK LOAD. AMLP #8 IS OFF, AMLP #1 & #5 ARE ON. SCENARIO 4
NO BATTERY. GOVS DISABLED. BERNICE LAKE UNIT IS OFF.

GENERATOR SUMMARY:

BUS	NAME BSVLT	#MAC	TYP	MW	MVAR	QMAX	QMIN	VSCHED	VACTUAL	REM
3	BELUGA3G13.8	1	3	62.7	8.9	24.8	-12.4	1.0150	1.0150	
5	BELUGA5G13.8	1	2	59.0	7.3	33.0	-16.5	1.0150	1.0150	
6	BELUGA6G13.8	1	2	78.0	9.9	37.1	-11.1	1.0180	1.0180	
7	BELUGA7G13.8	1	2	75.0	7.9	37.1	-11.1	1.0150	1.0150	
8	BELUGA8G13.8	1	2	54.0	8.2	30.0	-15.0	1.0150	1.0150	
24	EKLUT 2G6.90	1	2	16.0	4.3	7.3	-2.2	1.0000	1.0000	
25	EKLUT 1G6.90	1	2	16.0	4.3	7.3	-2.2	1.0000	1.0000	
34	TEELAND 13.8	1	2	0.0	10.1	22.0	-22.0	1.0050	1.0050	15
79	COOP1&2G4.20	2	2	16.0	5.7	14.7	-9.2	1.0300	1.0300	
121	FORT W. 12.4	4	2	7.5	1.7	5.4	-2.6	1.0500	1.0500	
201	GLDHLSVS13.8	1	-2	0.0	33.0	33.0	-5.0	1.0280	1.0199	202
210	N. POLE 13.8	2	2	50.0	7.7	34.8	-17.4	0.9860	0.9860	
213	CHENA 12.5	3	2	20.0	9.9	12.2	-4.0	1.0350	1.0350	
368	HEALYSVS12.0	1	2	0.0	7.1	22.0	-33.0	1.0220	1.0220	37
370	HEALY 1G13.8	1	2	25.0	3.1	15.5	-7.5	1.0140	1.0140	
501	BRADLY1G13.8	1	2	45.0	7.7	19.7	-19.7	1.0000	1.0000	
502	BRADLY2G13.8	1	2	45.0	7.8	19.7	-19.7	1.0000	1.0000	
600	PLNT2 5G13.8	1	-2	18.8	17.1	17.1	-8.5	1.0150	0.9958	
601	PLNT2 6G13.8	1	2	23.0	18.4	20.5	-10.2	1.0200	1.0200	
602	PLNT2 7G13.8	1	2	72.0	40.2	49.7	-24.8	1.0000	1.0000	
607	PLNT1 1G13.8	1	2	5.0	6.4	9.4	-4.7	1.0200	1.0200	
691	TESORO1G24.9	1	-2	4.1	1.5	1.5	1.5	1.0300	1.0237	
SUBSYSTEM TOTALS				692.1	228.4	473.7	-257.3	MVABASE=		1026.2

PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E SUN, DEC 29 1991 13:14
1989 SUMMER NORMAL LOAD. BELUGA 1 & 2 AT 5MW EACH.
NO BATTERY AT INTL 34.5KV.

SCENARIO 5

GENERATOR SUMMARY:

BUS	NAME BSVLT	#MAC	TYP	MW	MVAR	QMAX	QMIN	VSCHED	VACTUAL	REM
1	BELUGA1G13.8	1	2	5.0	-3.6	9.9	-4.9	1.0150	1.0150	
2	BELUGA2G13.8	1	2	5.0	-4.5	9.9	-4.9	1.0100	1.0100	
3	BELUGA3G13.8	1	3	31.6	-15.8	24.8	-12.4	1.0150	1.0150	
6	BELUGA6G13.8	1	-2	59.0	-11.1	37.1	-11.1	1.0180	1.0233	
8	BELUGA8G13.8	1	-2	24.0	-15.0	30.0	-15.0	1.0150	1.0202	
24	EKLUT 2G6.90	1	-2	7.0	-2.2	7.3	-2.2	1.0000	1.0218	
34	TEELAND 13.8	1	-2	0.0	-22.0	22.0	-22.0	1.0050	1.0253	15
121	FORT W. 12.4	4	2	5.9	0.1	5.4	-2.6	1.0500	1.0500	
201	GLDHLSVS13.8	1	2	0.0	15.9	33.0	-5.0	1.0280	1.0280	202
213	CHENA 12.5	3	2	12.5	2.0	12.2	-4.0	1.0350	1.0350	
368	HEALYSVS12.0	1	2	0.0	-19.7	22.0	-33.0	1.0220	1.0220	37
370	HEALY 1G13.8	1	2	25.0	3.1	15.5	-7.5	1.0140	1.0140	
501	BRADLY1G13.8	1	2	15.0	-7.1	19.7	-19.7	1.0000	1.0000	
502	BRADLY2G13.8	1	2	15.0	-7.1	19.7	-19.7	1.0000	1.0000	
601	PLNT2 6G13.8	1	2	12.0	-6.4	20.5	-10.2	1.0200	1.0200	
602	PLNT2 7G13.8	1	2	38.0	6.9	49.7	-24.8	1.0000	1.0000	
691	TESORO1G24.9	1	-2	4.1	1.5	1.5	1.5	1.0300	1.0441	
SUBSYSTEM TOTALS				259.0	-85.1	340.2	-197.5	MVABASE=		749.9

PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E SUN, DEC 29 1991 13:14
1989 SUMMER NORMAL LOAD. BELUGA 1 AT 5MW.
15 MVA BATTERY AT INTL 34.5KV, 0 MW OUTPUT. SCENARIO 6

GENERATOR SUMMARY:

BUS	NAME BSVLT	#MAC	TYP	MW	MVAR	QMAX	QMIN	VSCHED	VACTUAL	REM
1	BELUGA1G13.8	1	2	5.0	-4.1	9.9	-4.9	1.0150	1.0150	
3	BELUGA3G13.8	1	3	36.6	-17.9	24.8	-12.4	1.0150	1.0150	
6	BELUGA6G13.8	1	-2	59.0	-11.1	37.1	-11.1	1.0180	1.0267	
8	BELUGA8G13.8	1	-2	24.0	-15.0	30.0	-15.0	1.0150	1.0235	
24	EKLUT 2G6.90	1	-2	7.0	-2.2	7.3	-2.2	1.0000	1.0238	
34	TEELAND 13.8	1	-2	0.0	-22.0	22.0	-22.0	1.0050	1.0274	15
42	INTRNATL34.5	1	-2	0.0	0.0	0.0	0.0	1.0000	1.0531	
121	FORT W. 12.4	4	2	5.9	0.1	5.4	-2.6	1.0500	1.0500	
201	GLDHLSVS13.8	1	2	0.0	15.8	33.0	-5.0	1.0280	1.0280	202
213	CHENA 12.5	3	2	12.5	2.0	12.2	-4.0	1.0350	1.0350	
368	HEALYSVS12.0	1	2	0.0	-20.0	22.0	-33.0	1.0220	1.0220	37
370	HEALY 1G13.8	1	2	25.0	3.1	15.5	-7.5	1.0140	1.0140	
501	BRADLY1G13.8	1	2	15.0	-7.3	19.7	-19.7	1.0000	1.0000	
502	BRADLY2G13.8	1	2	15.0	-7.3	19.7	-19.7	1.0000	1.0000	
601	PLNT2 6G13.8	1	2	12.0	-7.2	20.5	-10.2	1.0200	1.0200	
602	PLNT2 7G13.8	1	2	38.0	5.9	49.7	-24.8	1.0000	1.0000	
691	TESORO1G24.9	1	-2	4.1	1.5	1.5	1.5	1.0300	1.0449	
SUBSYSTEM TOTALS				259.1	-85.6	330.3	-192.6	MVABASE=		761.1

PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E SUN, DEC 29 1991 13:15
1989 SUMMER NORMAL LOAD. BRADLEY 1 & 2 EACH AT 15MW.
30 MVA BATTERY AT INTL 34.5KV, 0 MW OUTPUT. SCENARIO 7

GENERATOR SUMMARY:

BUS	NAME BSVLT	#MAC	TYP	MW	MVAR	QMAX	QMIN	VSCHED	VACTUAL	REM
3	BELUGA3G13.8	1	3	41.6	-20.0	24.8	-12.4	1.0150	1.0150	
6	BELUGA6G13.8	1	-2	59.0	-11.1	37.1	-11.1	1.0180	1.0300	
8	BELUGA8G13.8	1	-2	24.0	-15.0	30.0	-15.0	1.0150	1.0269	
24	EKLUT 2G6.90	1	-2	7.0	-2.2	7.3	-2.2	1.0000	1.0260	
34	TEELAND 13.8	1	-2	0.0	-22.0	22.0	-22.0	1.0050	1.0295	15
42	INTRNATL34.5	1	-2	0.0	0.0	0.0	0.0	1.0000	1.0558	
121	FORT W. 12.4	4	2	5.9	0.1	5.4	-2.6	1.0500	1.0500	
201	GLDHLSVS13.8	1	2	0.0	15.9	33.0	-5.0	1.0280	1.0280	202
213	CHENA 12.5	3	2	12.5	2.0	12.2	-4.0	1.0350	1.0350	
368	HEALYSVS12.0	1	2	0.0	-20.2	22.0	-33.0	1.0220	1.0220	37
370	HEALY 1G13.8	1	2	25.0	3.1	15.5	-7.5	1.0140	1.0140	
501	BRADLY1G13.8	1	2	15.0	-7.4	19.7	-19.7	1.0000	1.0000	
502	BRADLY2G13.8	1	2	15.0	-7.4	19.7	-19.7	1.0000	1.0000	
601	PLNT2 6G13.8	1	2	12.0	-8.0	20.5	-10.2	1.0200	1.0200	
602	PLNT2 7G13.8	1	2	38.0	4.8	49.7	-24.8	1.0000	1.0000	
691	TESORO1G24.9	1	-2	4.1	1.5	1.5	1.5	1.0300	1.0458	
SUBSYSTEM TOTALS				259.1	-86.0	320.4	-187.7	MVABASE=		772.3

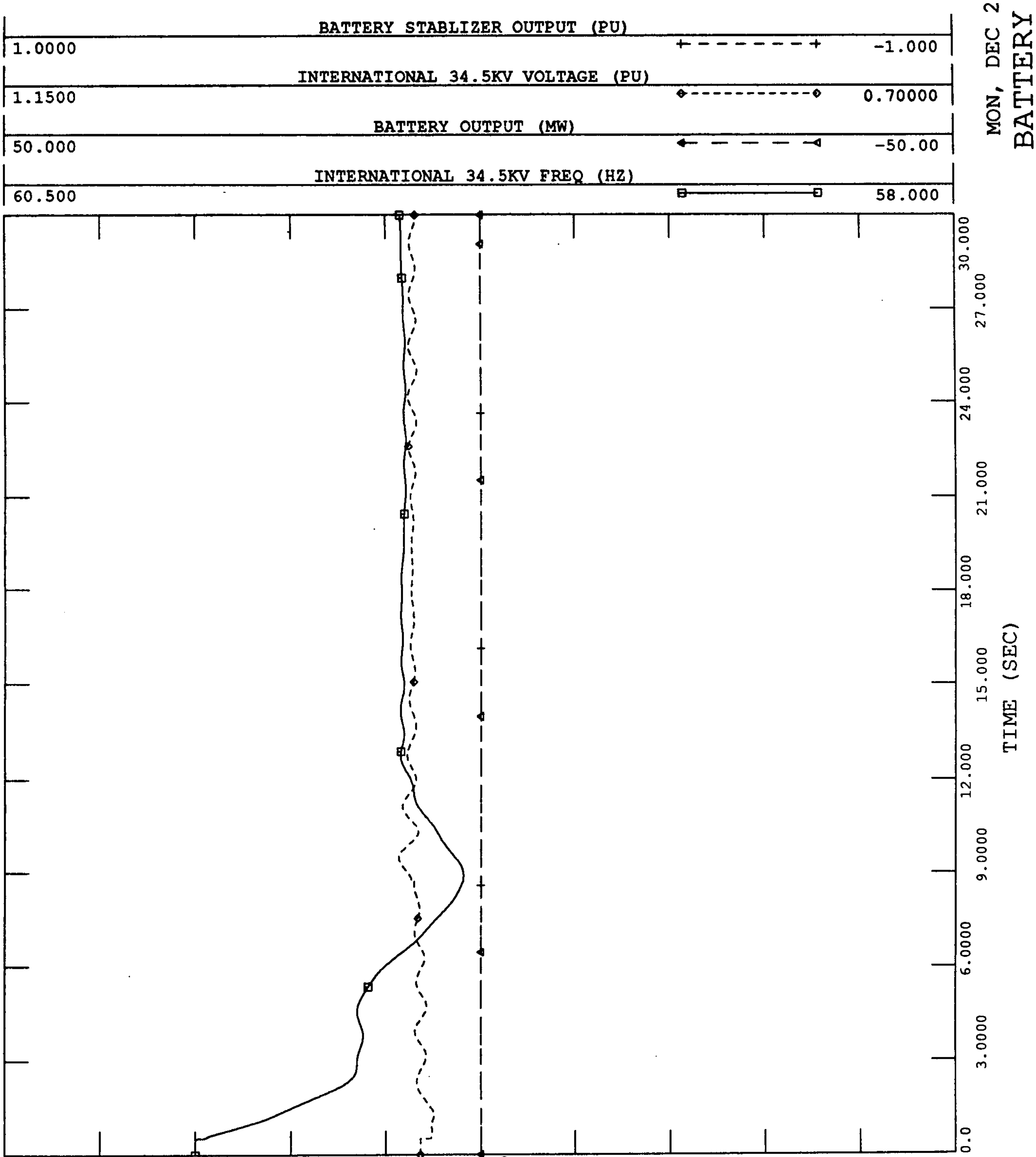
C

STABILITY ANALYSIS: SCENARIO 1

This appendix contains the simulations of Scenario 1. Battery sizes from 15 to 30 MW and droop settings of 0.5% and 1% were used. A simulation case was also run in which no battery was used. In this scenario, the disturbance consisted of a 54 MW loss of generation.

1991 WINTER PEAK LOAD. NO MVA BATTERY AT INTL. 34.5.
GOVERNORS DISABLED AT BELUGA 5,6,7, CHENA 5, HEALY.
TRIP BELUGA #8 AT 54 MW AT T=0.5 SECONDS.

FILE: GD-00.CHN

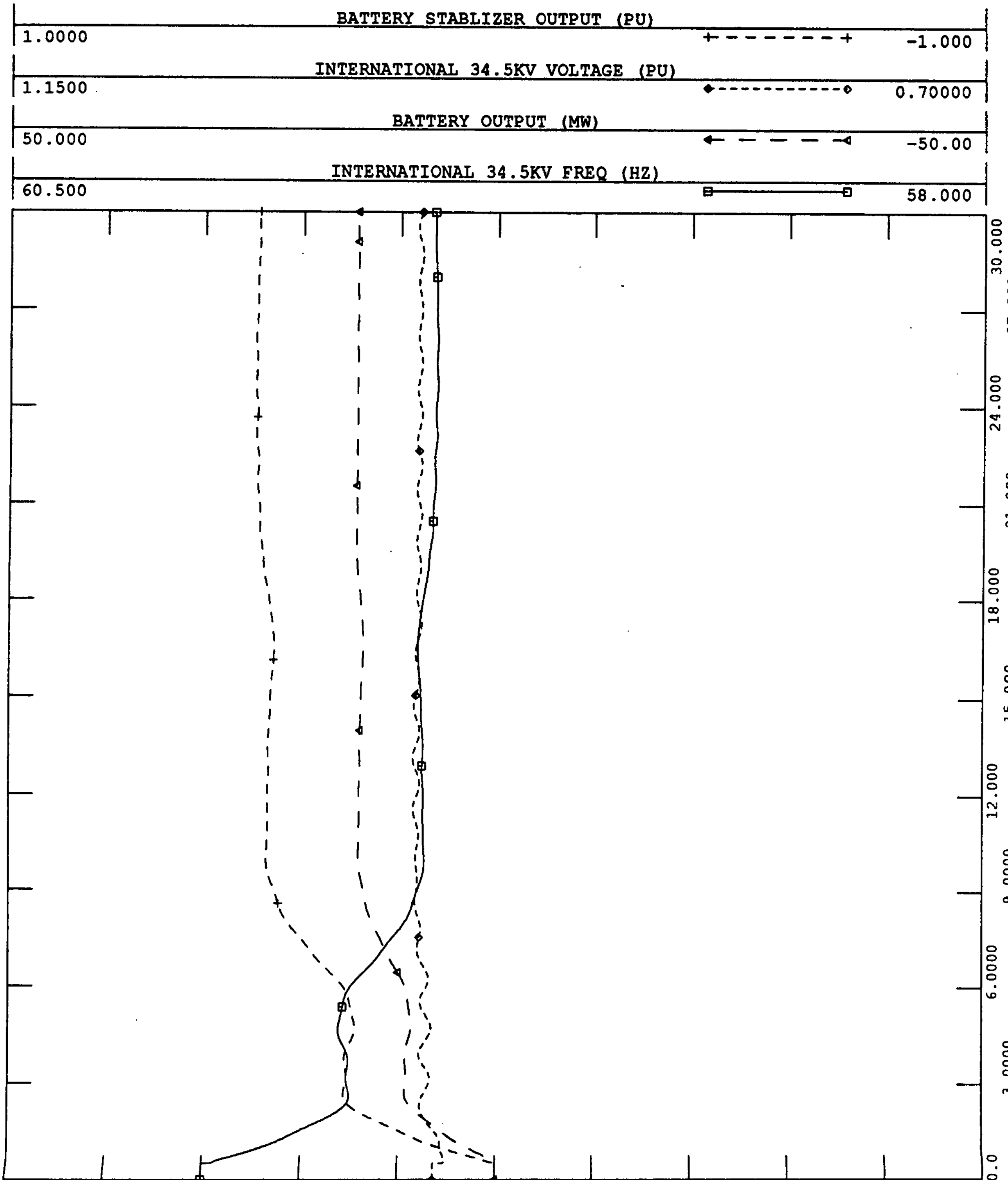


1991 WINTER PEAK LOAD. 15 MVA BATTERY AT INTL. 34.5.
GOVERNORS DISABLED AT BELUGA 5,6,7, CHENA 5, HEALY.
TRIP BELUGA #8 AT 54MW AT T=0.5 SECONDS. [redacted]% DROOP.

FILE: GD15-~~50~~ 01.CHN

MON, DEC 16 1991 15:49

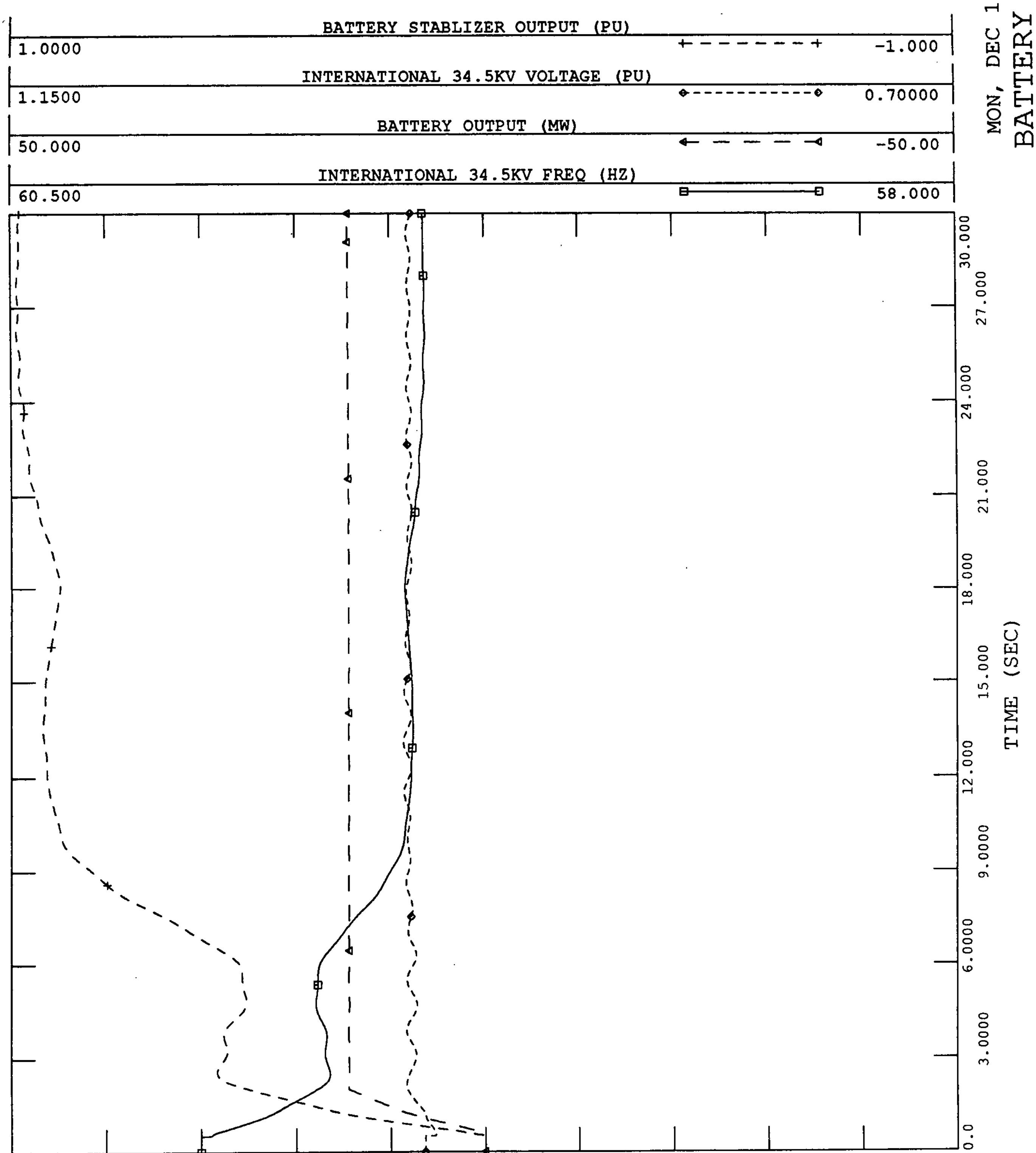
BATTERY RESPONSE



1991 WINTER PEAK LOAD. 15 MVA BATTERY AT INTL. 34.5.
GOVERNORS DISABLED AT BELUGA 5,6,7, CHENA 5, HEALY.
TRIP BELUGA #8 AT 54MW AT T=0.5 SECONDS. 0.5% DROOP.

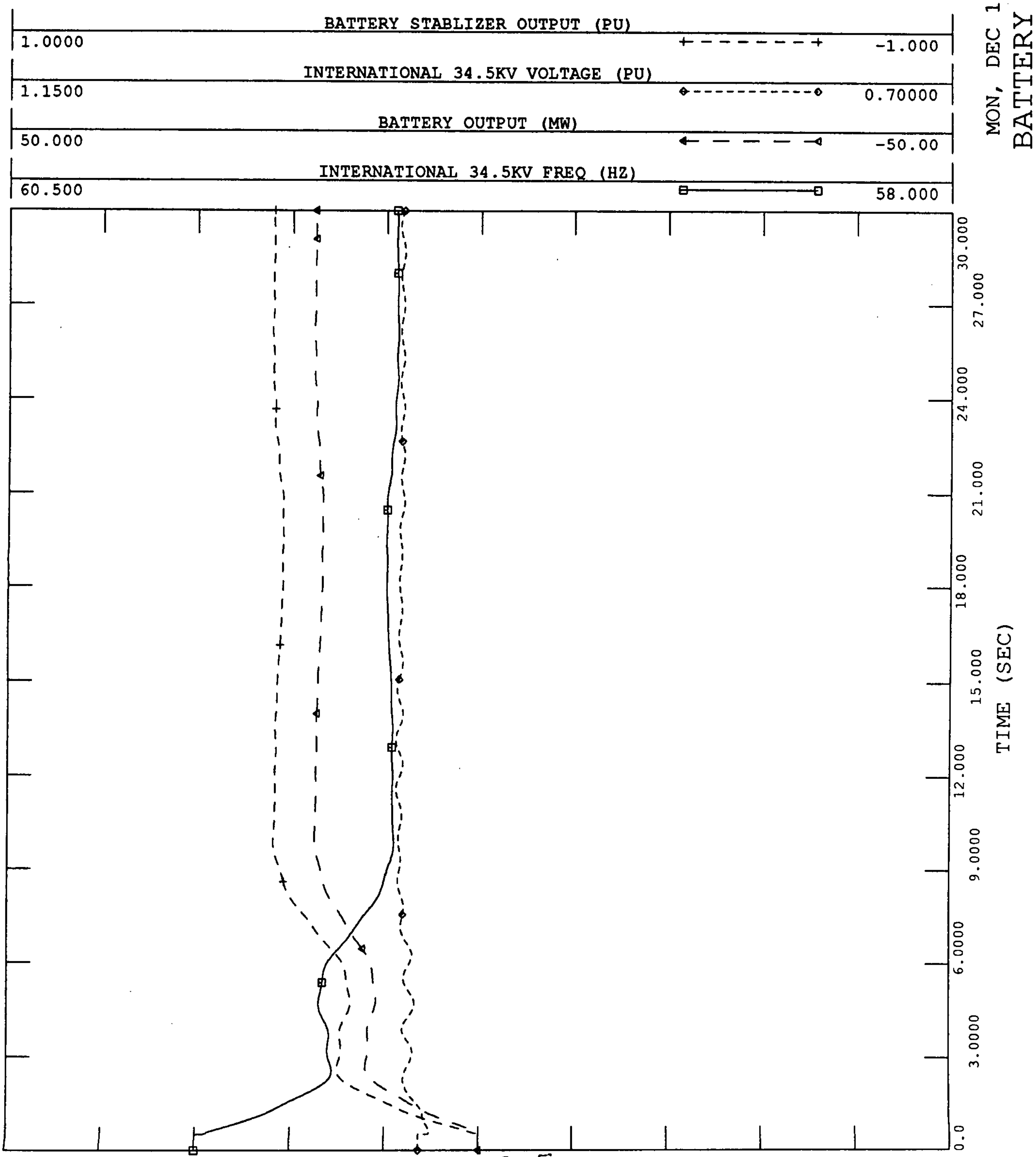
FILE: GD15-~~100~~ 005.CHN

MON, DEC 16 1991 15:53
BATTERY RESPONSE



1991 WINTER PEAK LOAD. 20 MVA BATTERY AT INTL. 34.5.
GOVERNORS DISABLED AT BELUGA 5,6,7, CHENA 5, HEALY.
TRIP BELUGA #8 AT 54MW AT T=0.5 SECONDS. 5% DROOP.

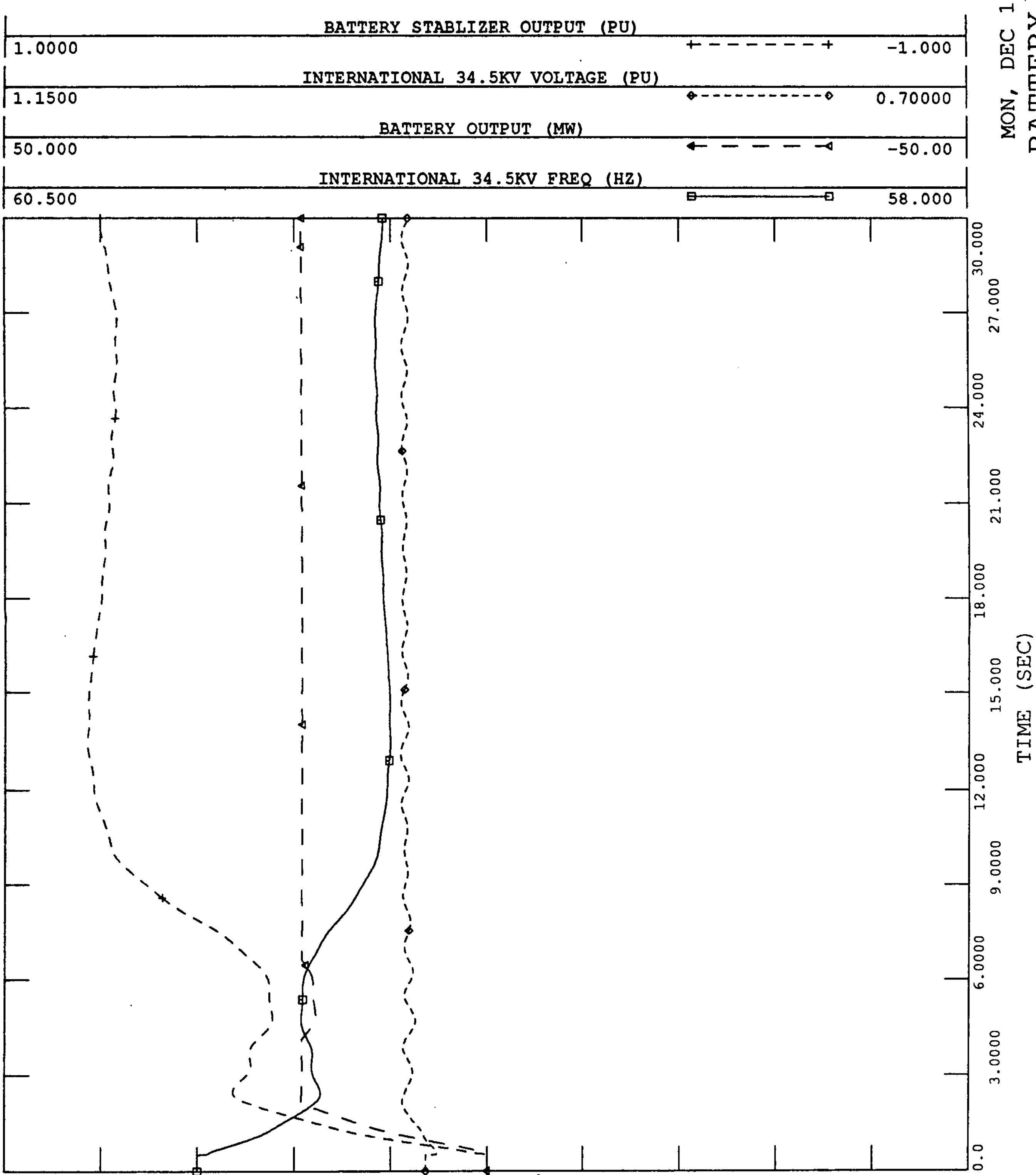
FILE: GD20-~~50~~01.CHN



1991 WINTER PEAK LOAD. 20 MVA BATTERY AT INTL. 34.5.
GOVERNORS DISABLED AT BELUGA 5,6,7, CHENA 5, HEALY.
TRIP BELUGA #8 AT 54MW AT T=0.5 SECONDS. 0.5% DROOP.

FILE: GD20-~~100~~ 005.CHN

MON, DEC 16 1991 15:55
BATTERY RESPONSE

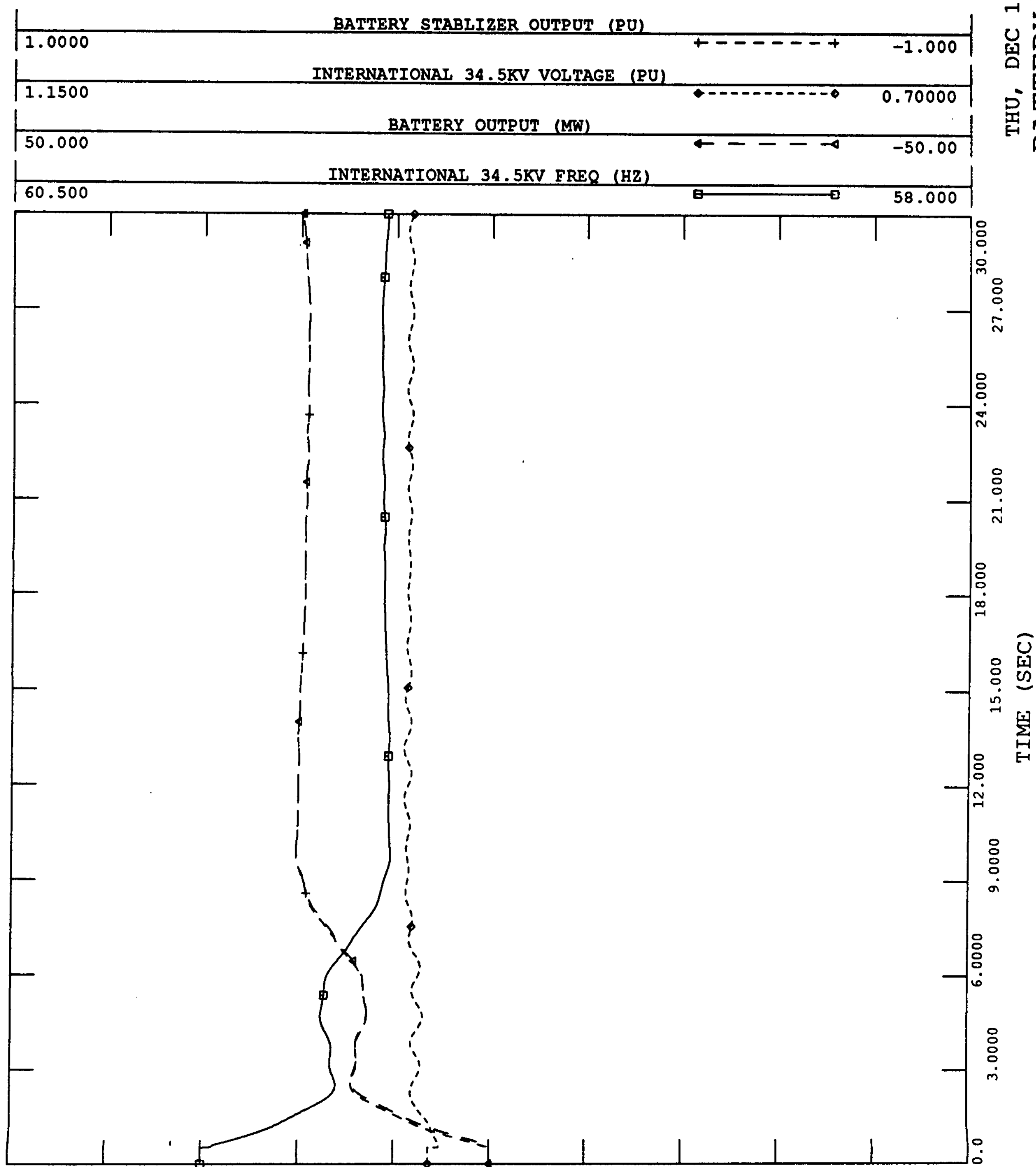


C-6

1991 WINTER PEAK LOAD. 25 MVA BATTERY AT INTL. 34.5.
GOVERNORS DISABLED AT BELUGA 5,6,7, CHENA 5, HEALY.
TRIP BELUGA #8 AT 54MW AT T=0.5 SECONDS. 1% DROOP.

FILE: GD25-01.CHN

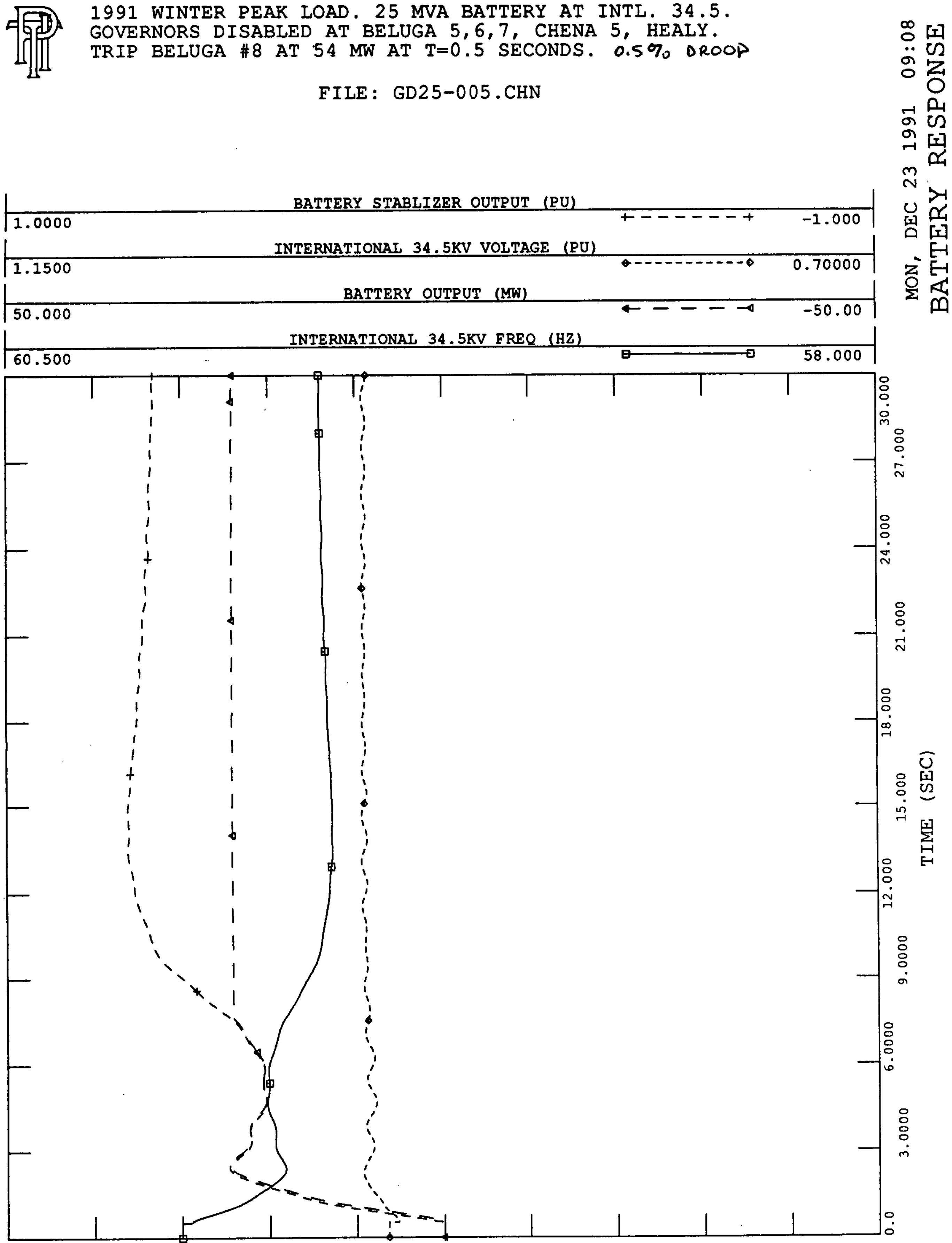
THU, DEC 19 1991 11:58
BATTERY RESPONSE



C-7

1991 WINTER PEAK LOAD. 25 MVA BATTERY AT INTL. 34.5.
GOVERNORS DISABLED AT BELUGA 5,6,7, CHENA 5, HEALY.
TRIP BELUGA #8 AT 54 MW AT T=0.5 SECONDS. 0.5% DROOP

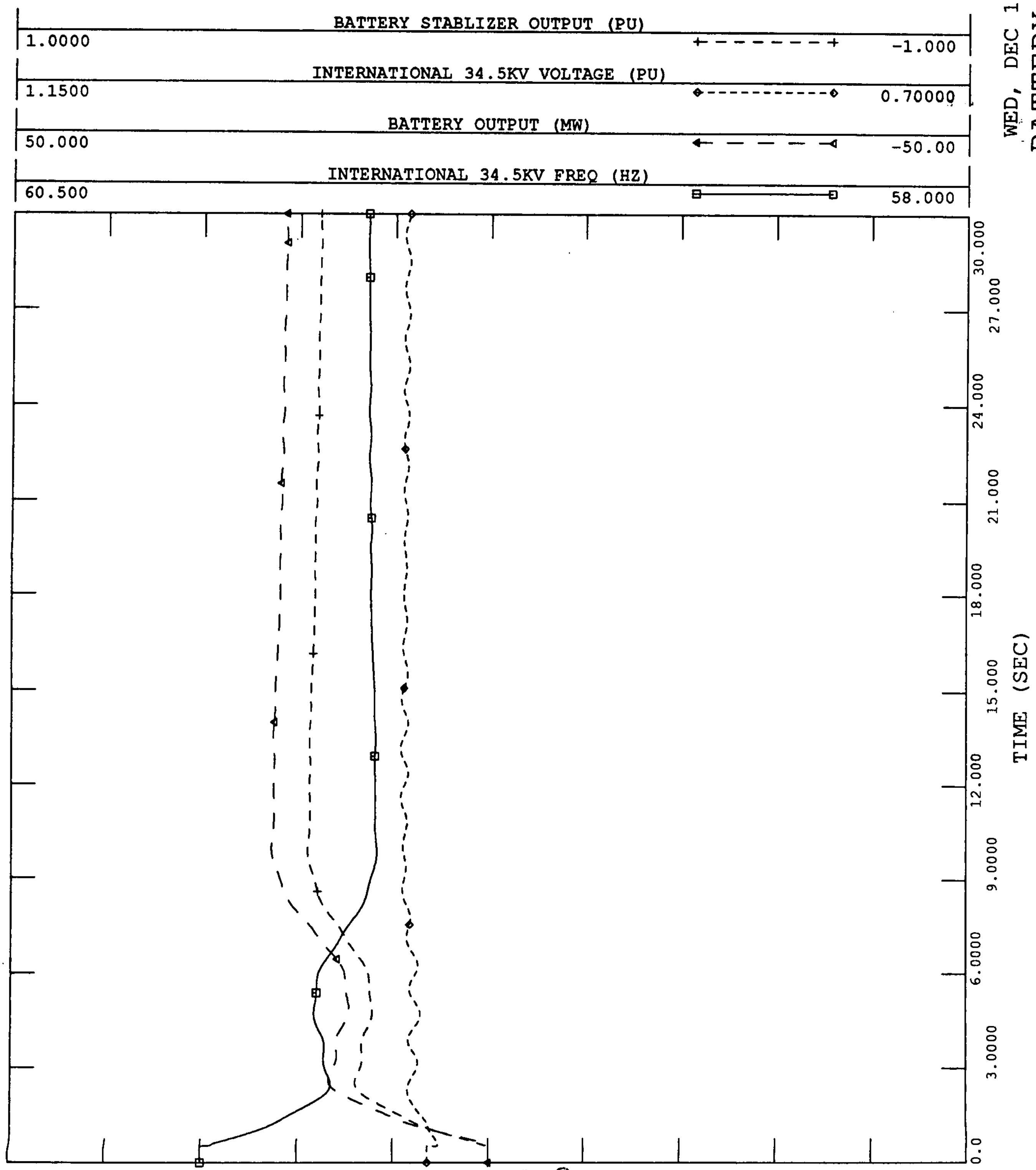
FILE: GD25-005.CHN



1991 WINTER PEAK LOAD. 30 MVA BATTERY AT INTL. 34.5.
GOVERNORS DISABLED AT BELUGA 5,6,7, CHENA 5, HEALY.
TRIP BELUGA #8 AT 54MW AT T=0.5 SECONDS. 1% DROOP.

FILE: GD30-01.CHN

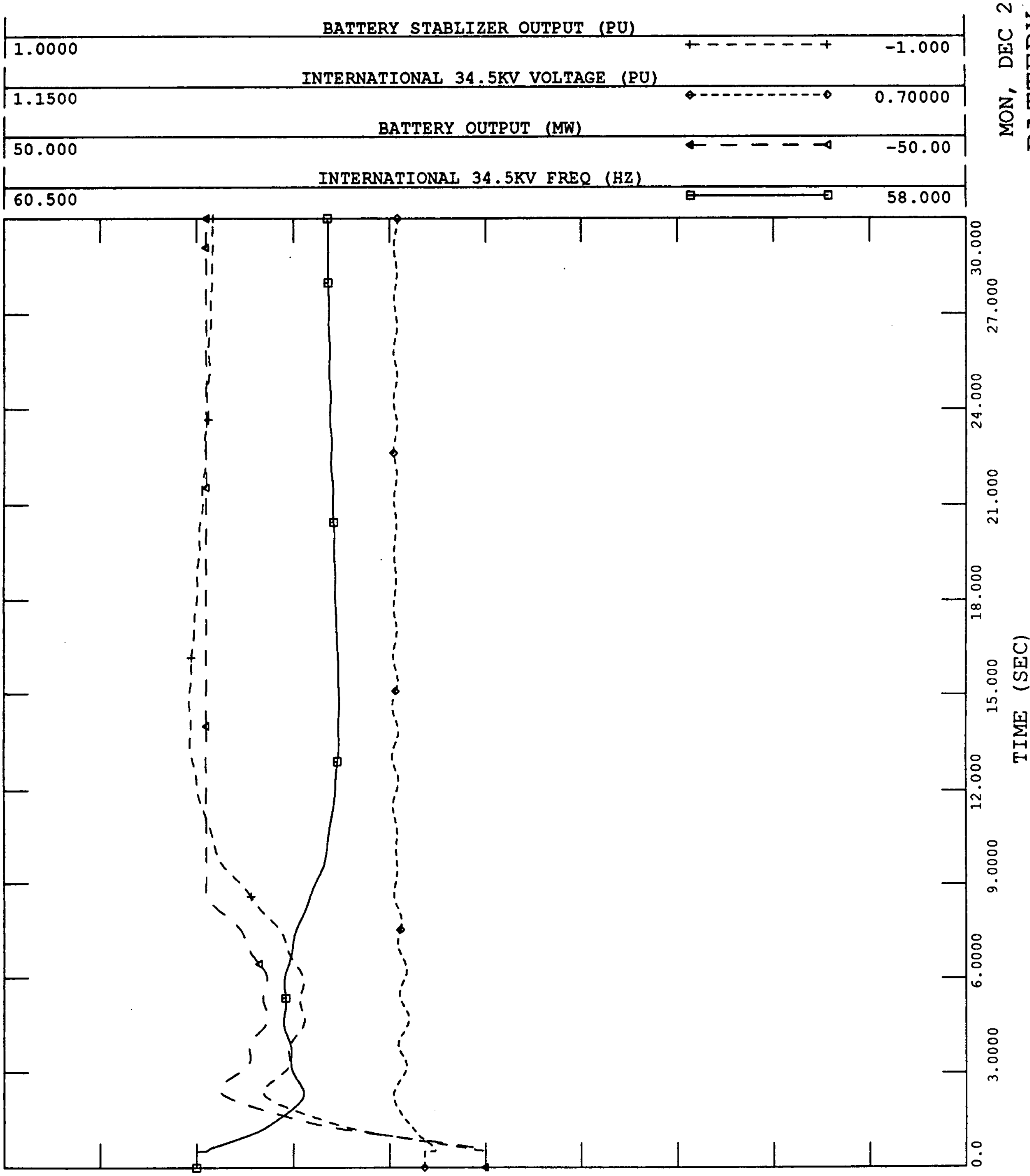
WED, DEC 18 1991 08:46
BATTERY RESPONSE



C-9

1991 WINTER PEAK LOAD. 30 MVA BATTERY AT INTL. 34.5.
GOVERNORS DISABLED AT BELUGA 5,6,7, CHENA 5, HEALY.
TRIP BELUGA #8 AT 54 MW AT T=0.5 SECONDS. 0.5% DROOP

FILE: GD30-005.CHN



MON, DEC 23 1991 09:10
BATTERY RESPONSE

C-10

D

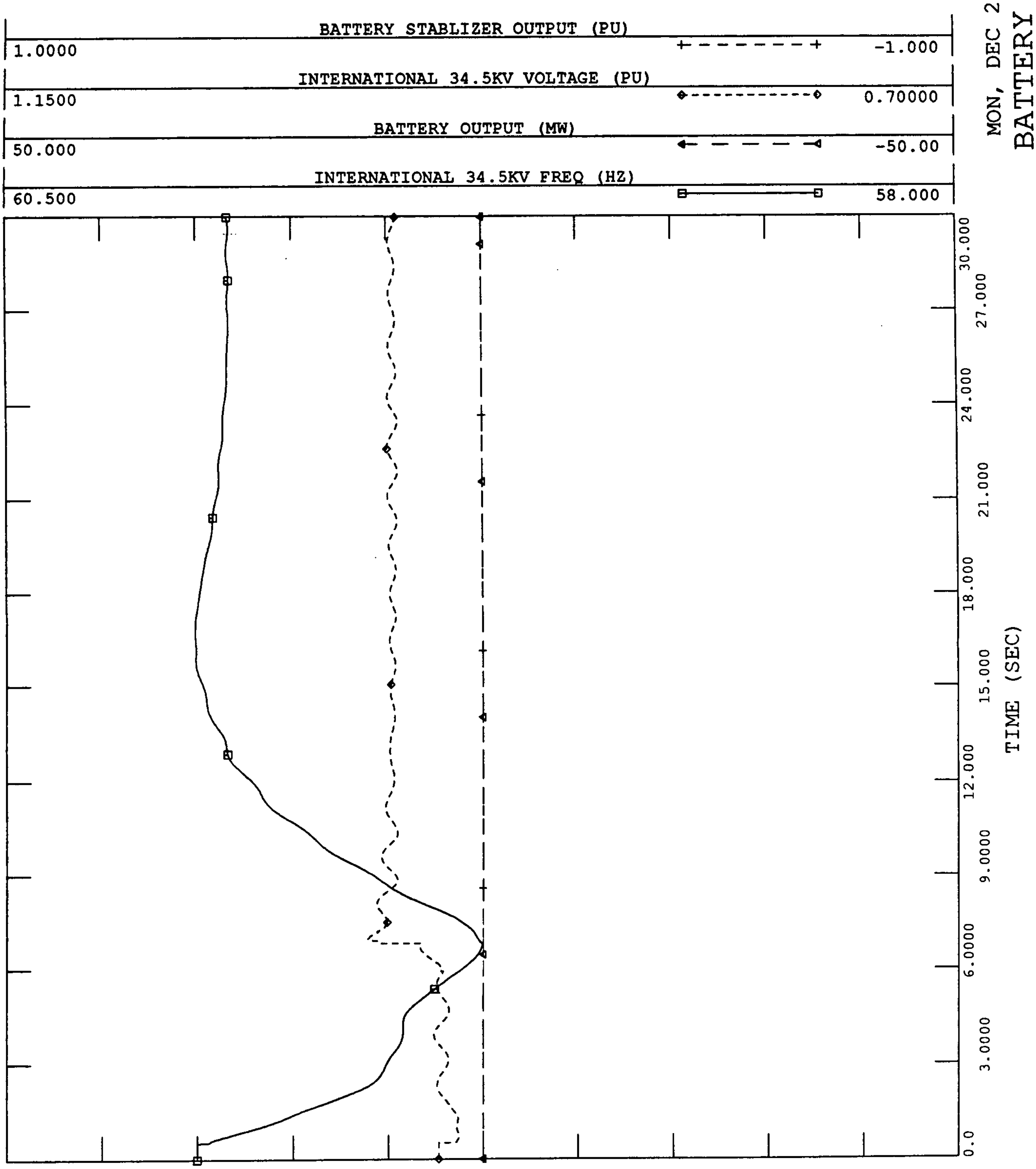
STABILITY ANALYSIS: SCENARIO 2

This appendix contains the simulations of Scenario 2. Battery sizes from 15 to 30 MW and droop settings of 0.5% and 1% were used. A simulation case was also run in which no battery was attached. For this scenario, the disturbance consisted of a 54 MW loss of generation.

1991 WINTER PEAK LOAD. AMLP #8 IS OFF, AMLP #1 & #5 ARE ON.
NO BATTERY AT INTL 34.5KV.
TRIP BELUGA #8 AT 54 MW AT T=0.5 SECONDS.

FILE: AM-00.CHN

MON, DEC 23 1991 08:59
BATTERY RESPONSE

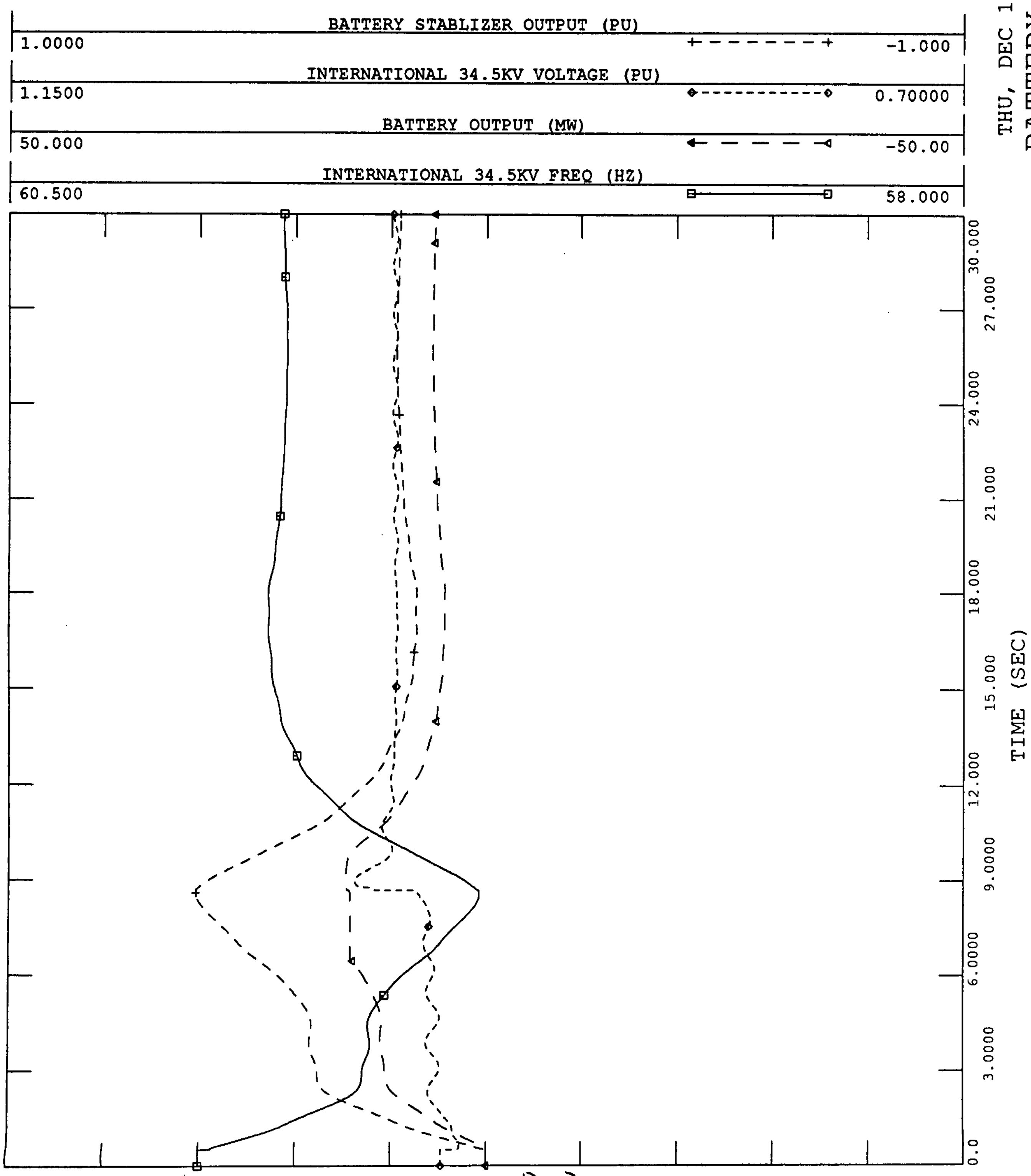


1991 WINTER PEAK LOAD. AMLP #8 IS OFF, AMLP #1 & #5 ARE ON.
15 MVA BATTERY AT INTL 34.5KV, 0 MW OUTPUT. GOVS DISABLED.
TRIP BELUGA #8 AT 54MW AT T=0.5 SECONDS. [redacted]% DROOP.

FILE: AM15-~~50~~01.CHN

THU, DEC 12 1991 09:13

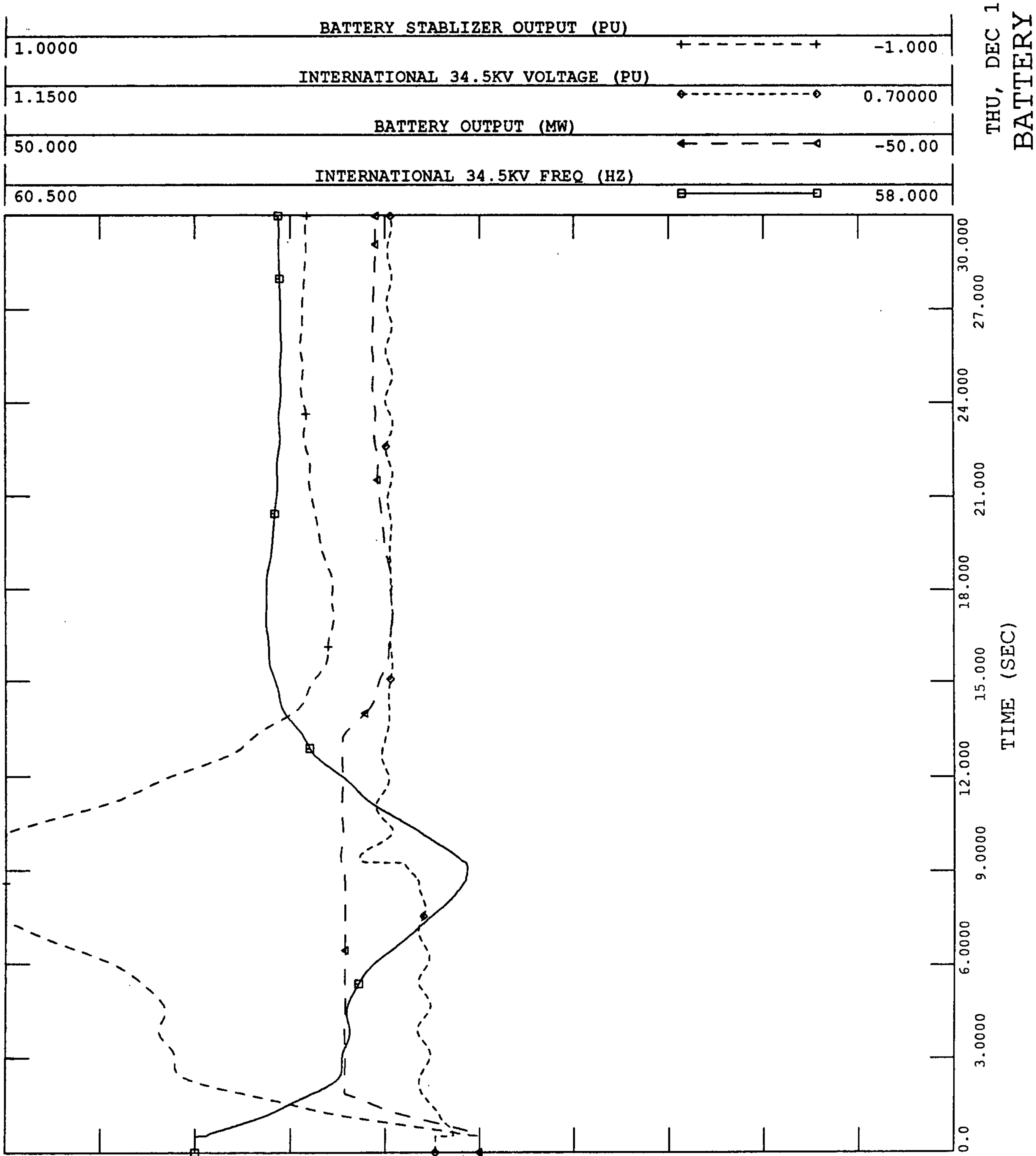
BATTERY RESPONSE



D-3

1991 WINTER PEAK LOAD. AMLP #8 IS OFF, AMLP #1 & #5 ARE ON.
15 MVA BATTERY AT INTL 34.5KV, 0 MW OUTPUT. GOVS DISABLED.
TRIP BELUGA #8 AT 54MW AT T=0.5 SECONDS. ~~1~~ 0.5% DROOP.

FILE: AM15-~~100~~ 005.CHN

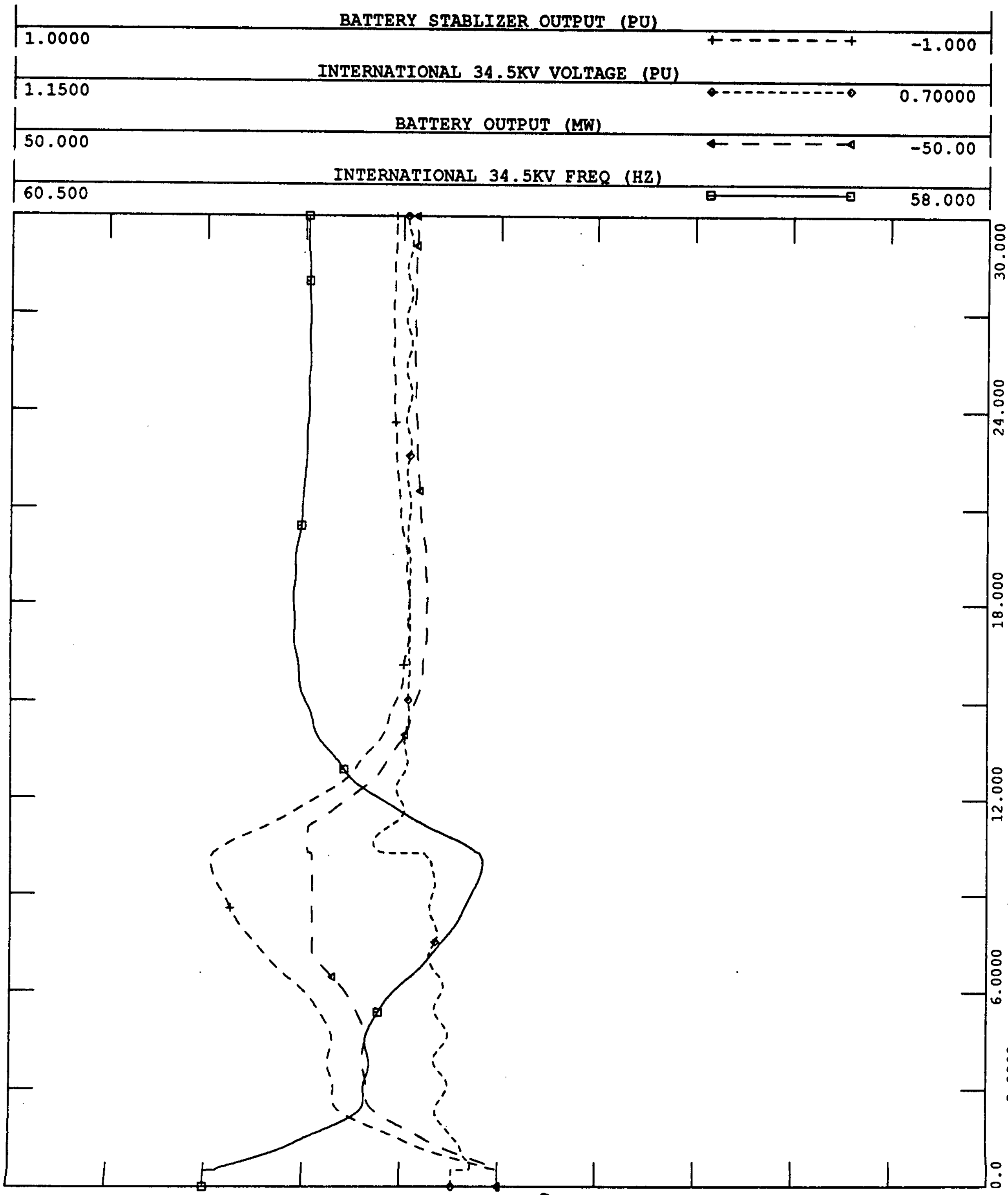


D-4

1991 WINTER PEAK LOAD. AMLP #8 IS OFF, AMLP #1 & #5 ARE ON.
20 MVA BATTERY AT INTL 34.5KV, 0 MW OUTPUT. GOVS DISABLED.
TRIP BELUGA #8 AT 54MW AT T=0.5 SECONDS. 1% DROOP.

FILE: AM20-~~50~~01.CHN

THU, DEC 12 1991 09:24
BATTERY RESPONSE

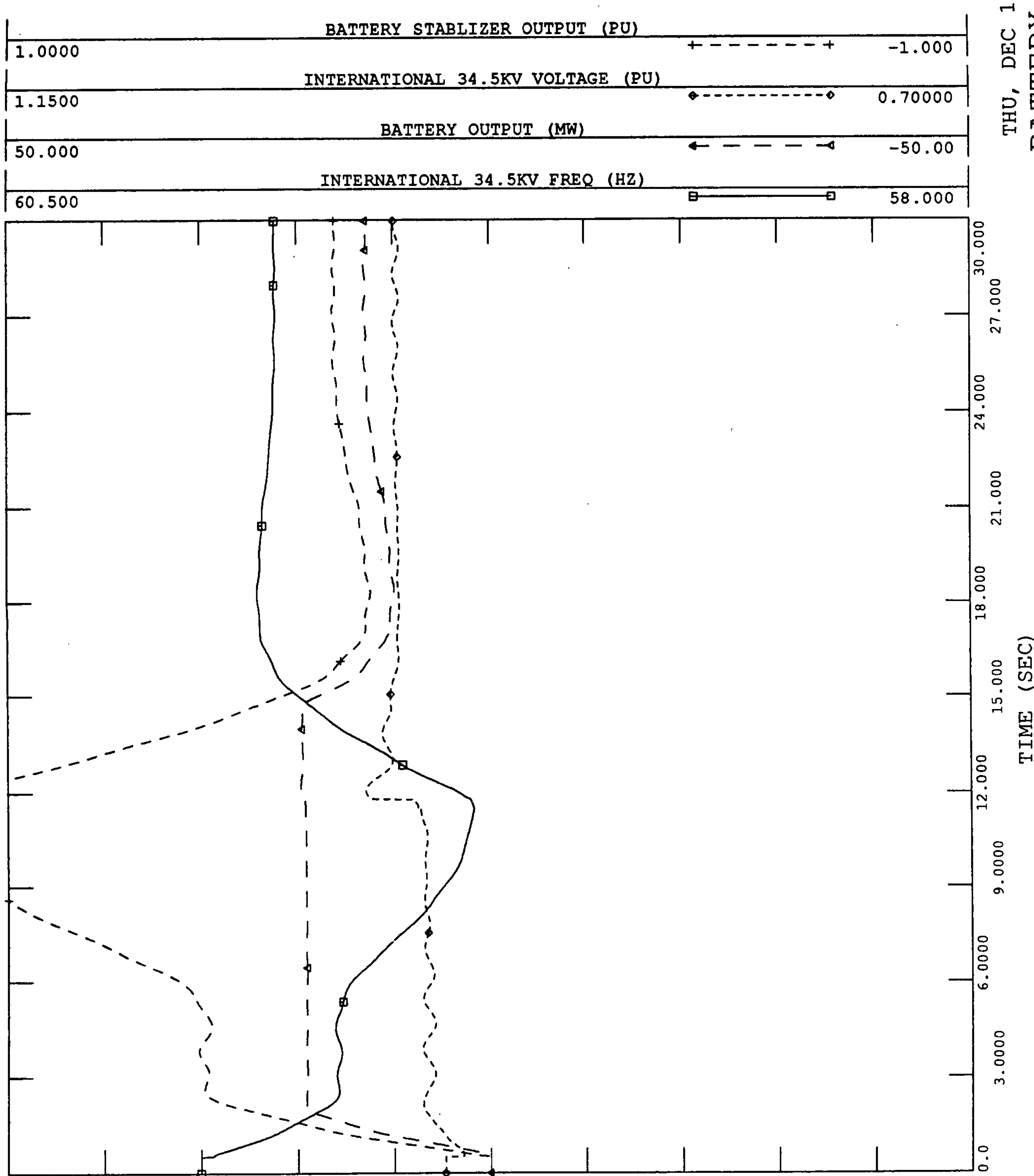


D-5

1991 WINTER PEAK LOAD. AMLP #8 IS OFF, AMLP #1 & #5 ARE ON.
20 MVA BATTERY AT INTL 34.5KV, 0 MW OUTPUT. GOVS DISABLED.
TRIP BELUGA #8 AT 54MW AT T=0.5 SECONDS. [redacted] DROOP. 0.5%

FILE: AM20-~~100~~ 005.CHN

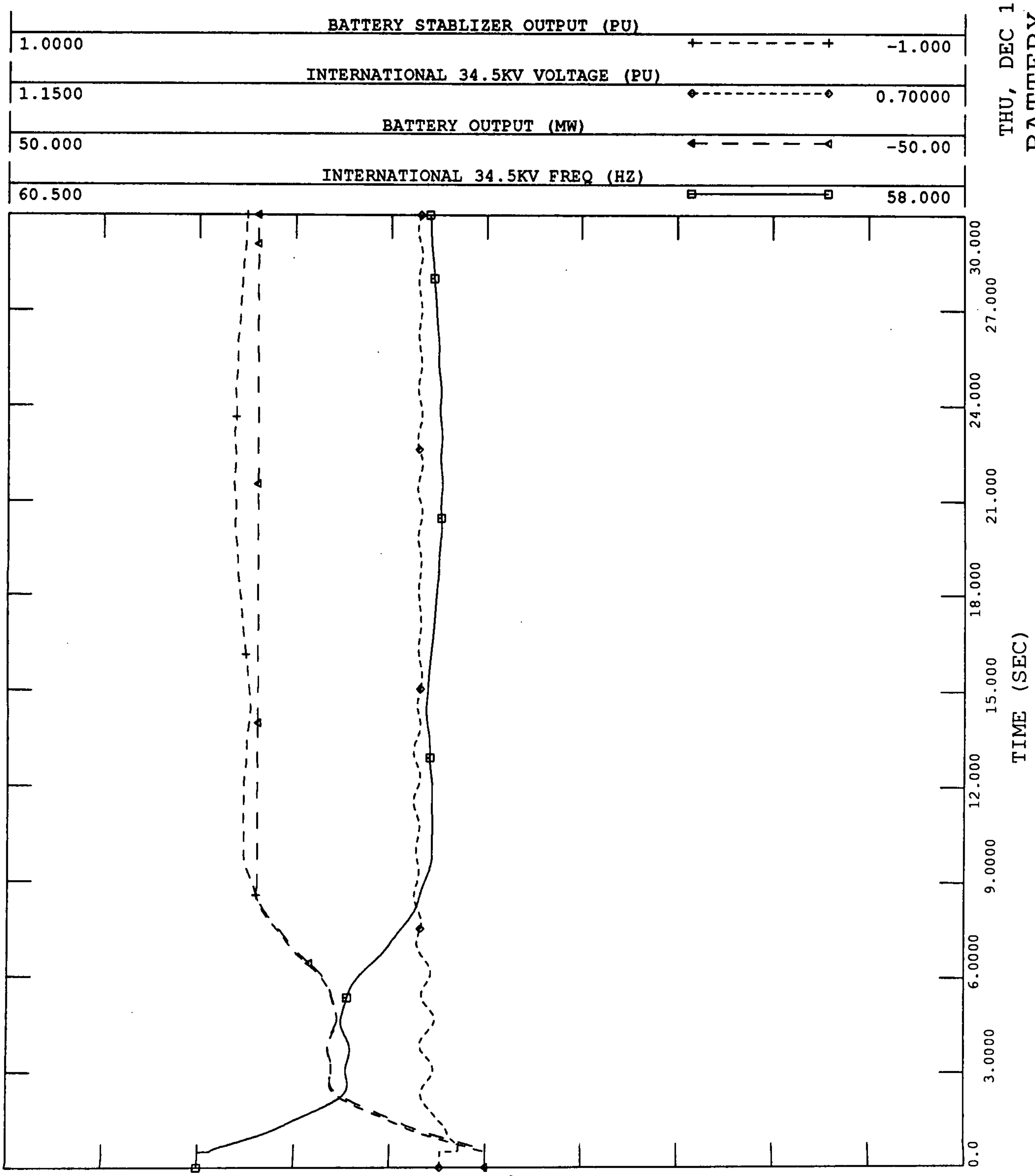
THU, DEC 12 1991 09:26
BATTERY RESPONSE



1991 WINTER PEAK LOAD. AMLP #8 IS OFF, AMLP #1 & #5 ARE ON.
25 MVA BATTERY AT INTL 34.5KV, 0 MW OUTPUT. GOVS DISABLED.
TRIP BELUGA #8 AT 54MW AT T=0.5 SECONDS. 1% DROOP.

FILE: AM25-01.CHN

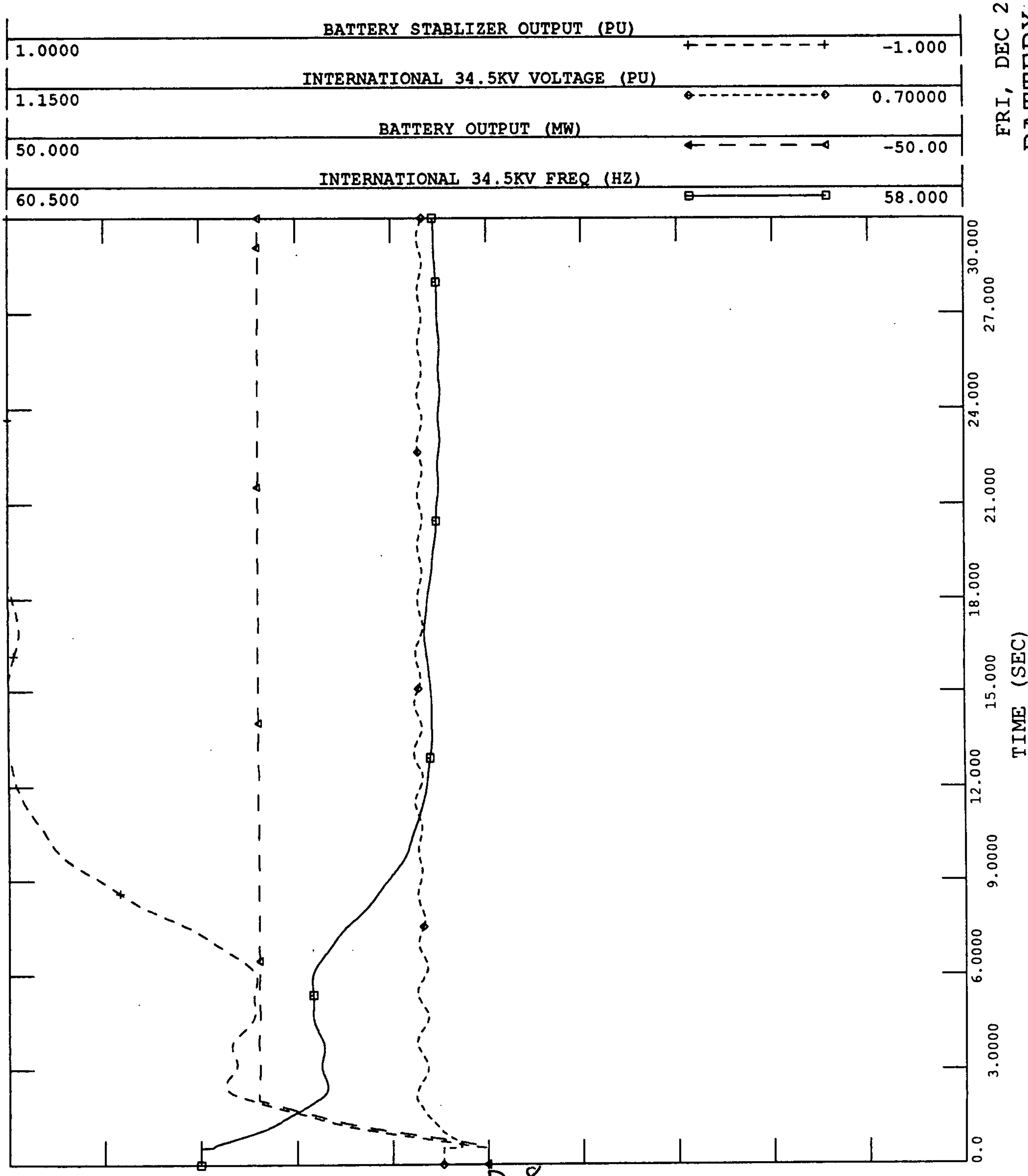
THU, DEC 19 1991 12:00
BATTERY RESPONSE



1991 WINTER PEAK LOAD. AMLP #8 IS OFF, AMLP #1 & #5 ARE ON.
25 MVA BATTERY AT INTL 34.5KV, 0 MW OUTPUT. GOVS DISABLED.
TRIP BELUGA #8 AT 54 MW AT T=0.5 SECONDS. 0.5 % DROOP

FILE: AM25-05.CHN

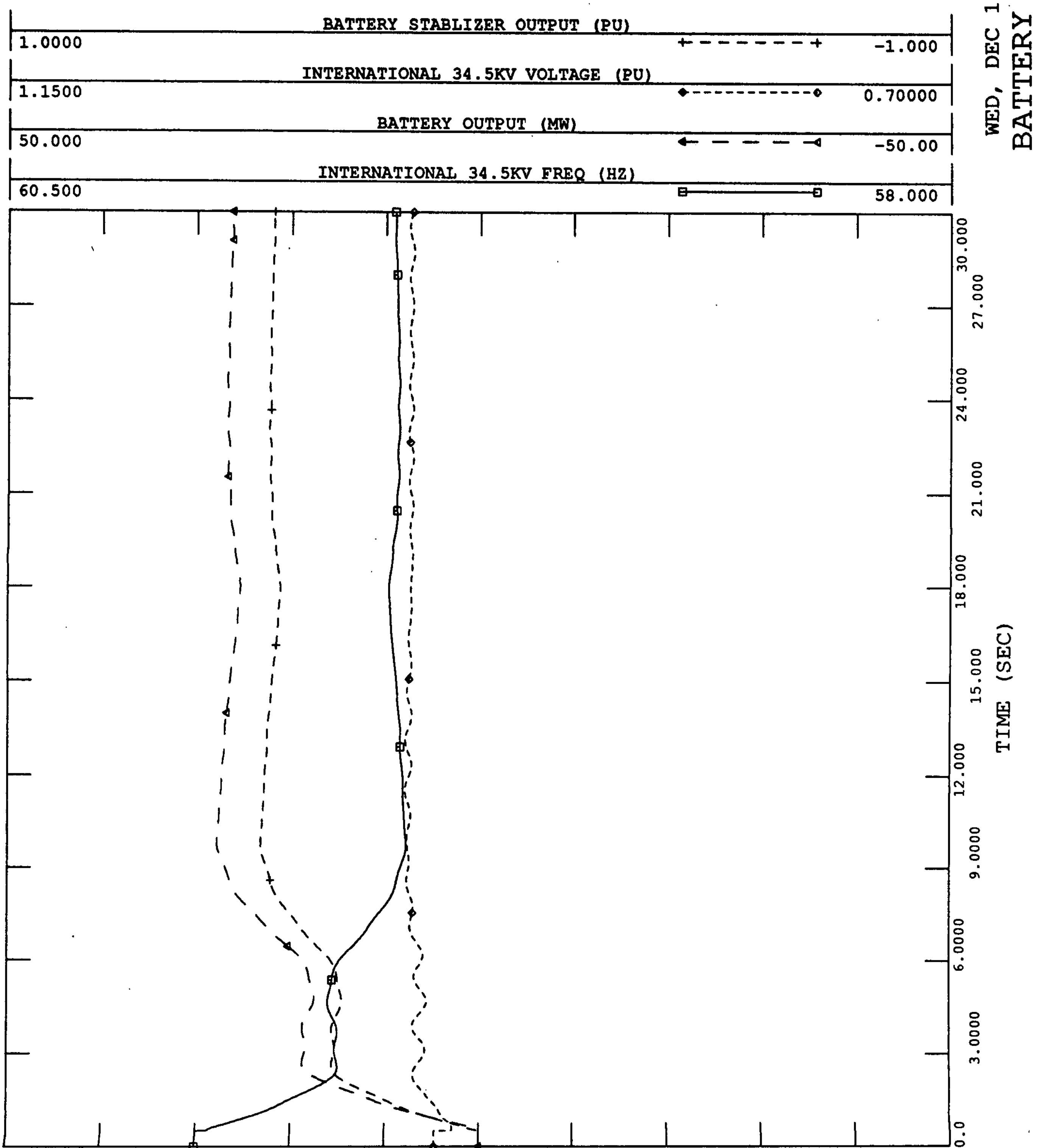
FRI, DEC 27 1991 13:34
BATTERY RESPONSE



D-8

1991 WINTER PEAK LOAD. AMLP #8 IS OFF, AMLP #1 & #5 ARE ON.
30 MVA BATTERY AT INTL 34.5KV, 0 MW OUTPUT. GOVS DISABLED.
TRIP BELUGA #8 AT 54MW AT T=0.5 SECONDS. 1% DROOP.

FILE: AM30-01.CHN

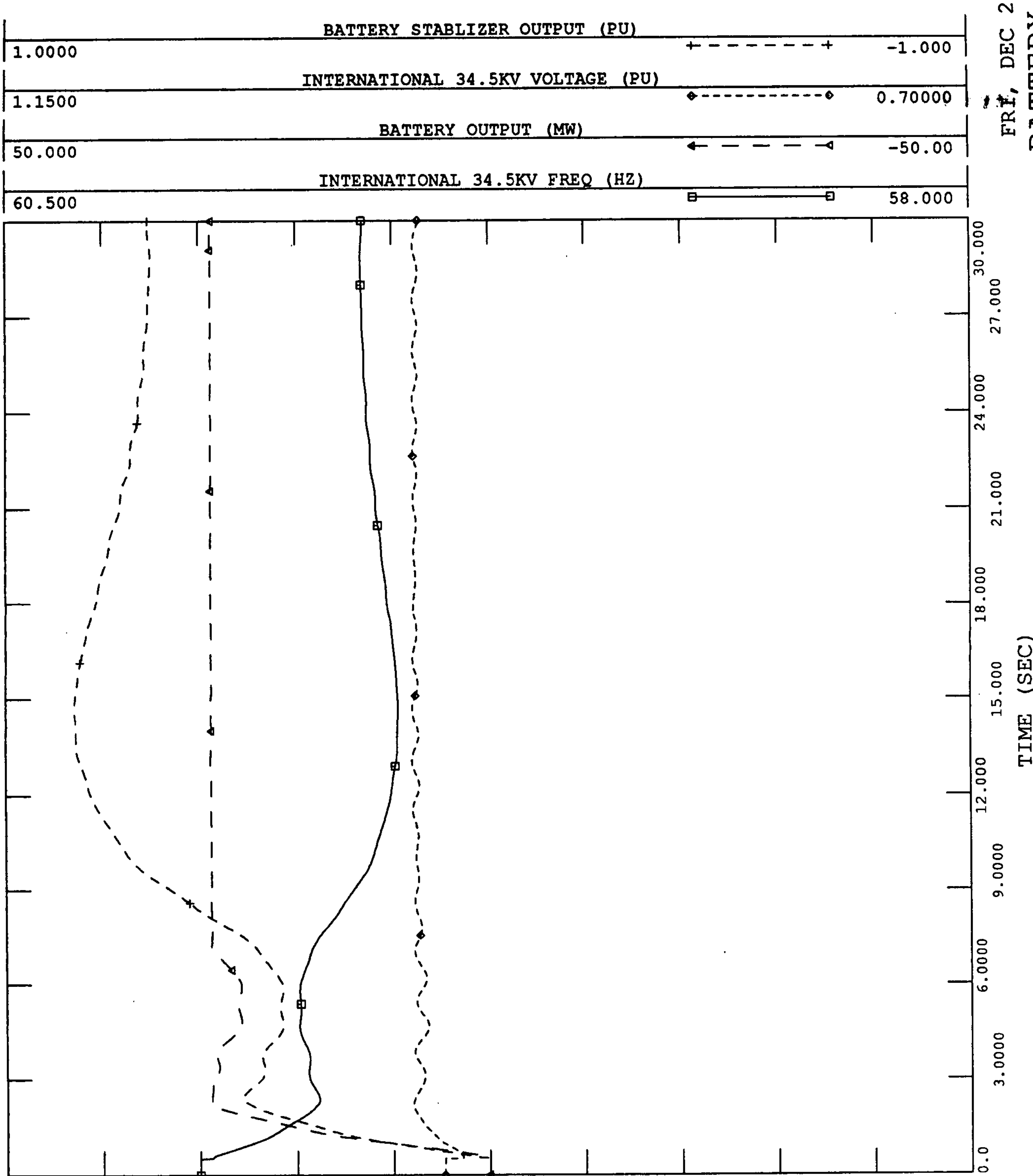


1991 WINTER PEAK LOAD. AMLP #8 IS OFF, AMLP #1 & #5 ARE ON.
30 BATTERY AT INTL 34.5KV. 0.5% DROOP
TRIP BELUGA #8 AT 54 MW AT T=0.5 SECONDS.

FILE: AM30-05.CHN

FRI, DEC 27 1991 13:36

BATTERY RESPONSE



D-10

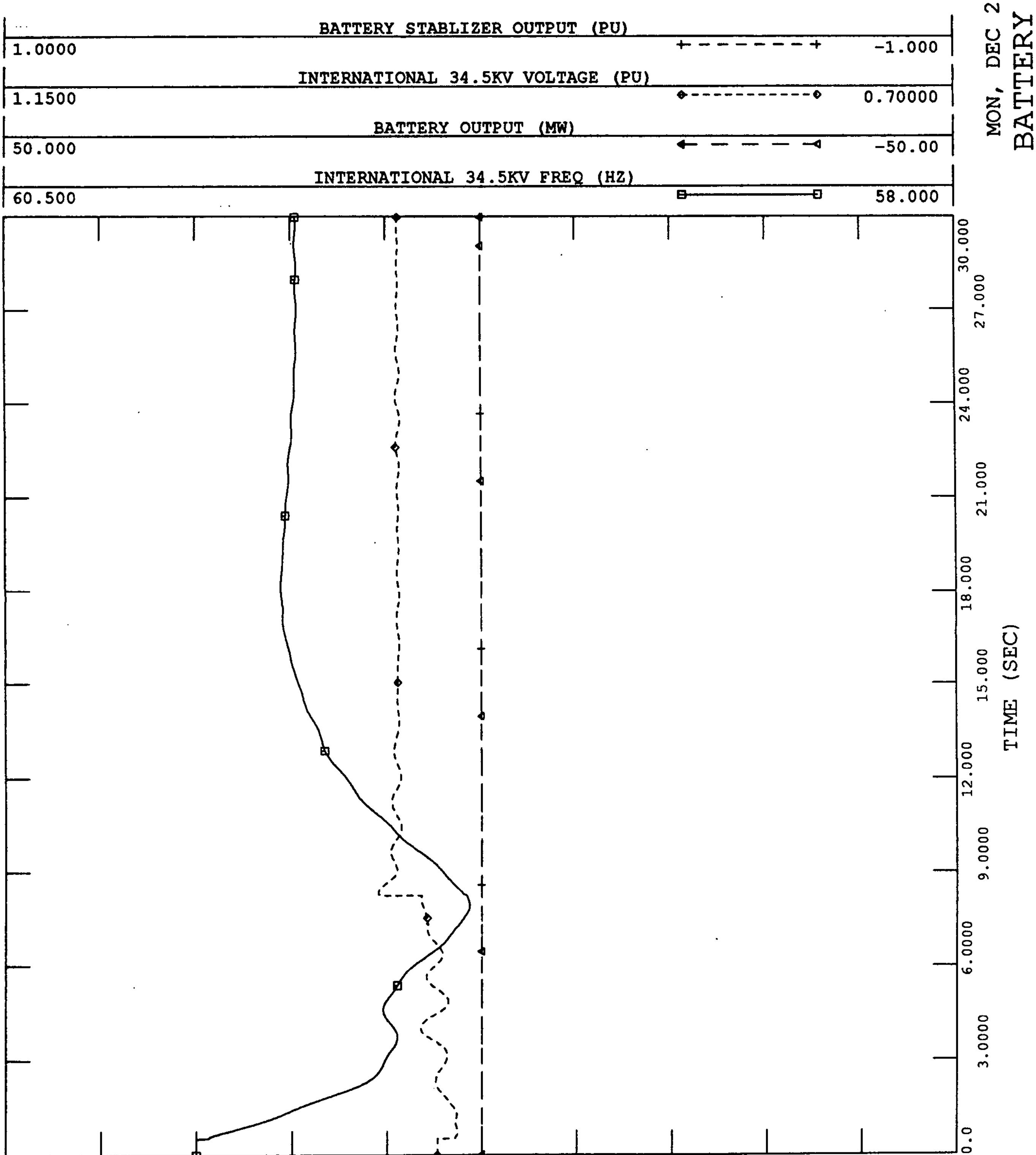
E

STABILITY ANALYSIS: SCENARIO 3

This appendix contains the simulations of Scenario 3. Battery sizes from 15 to 25 MW and droop settings of 0.5% and 1% were used. A simulation case was also run in which no battery was used. In this scenario, two disturbances were studied: a 54 MW loss of generation and a 95 MW loss of generation.

1991 WINTER PEAK LOAD. AMLP #8 IS OFF, AMLP #1 & #5 ARE ON.
NO BATTERY AT INTL 34.5KV.
TRIP BELUGA #8 AT 54 MW AT T=0.5 SECONDS.

FILE: AML-00.CHN

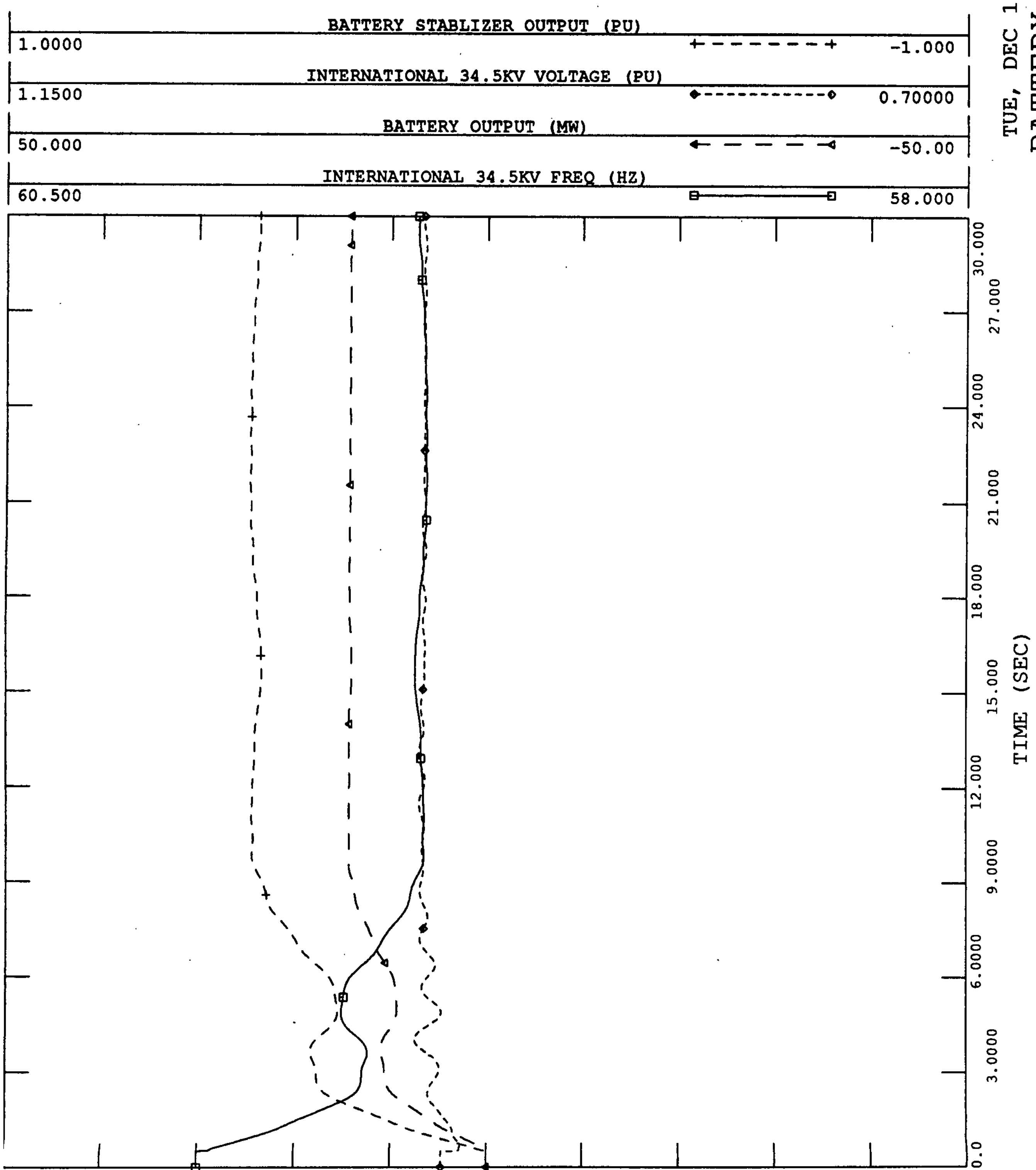


E-2

1991 WINTER PEAK LOAD. AMLP #8 IS OFF, AMLP #1 & #5 ARE ON.
15 MVA BATTERY AT INTL 34.5KV, 0 MW OUTPUT. GOVS DISABLED.
TRIP BELUGA #8 AT 54MW AT T=0.5 SECONDS. [redacted]% DROOP.
LOAD SHED RELAYS AT BUS 204 ACTIVATED.

FILE: ~~AM15-50L~~.CHN
AML15-01

TUE, DEC 17 1991 09:00
BATTERY RESPONSE

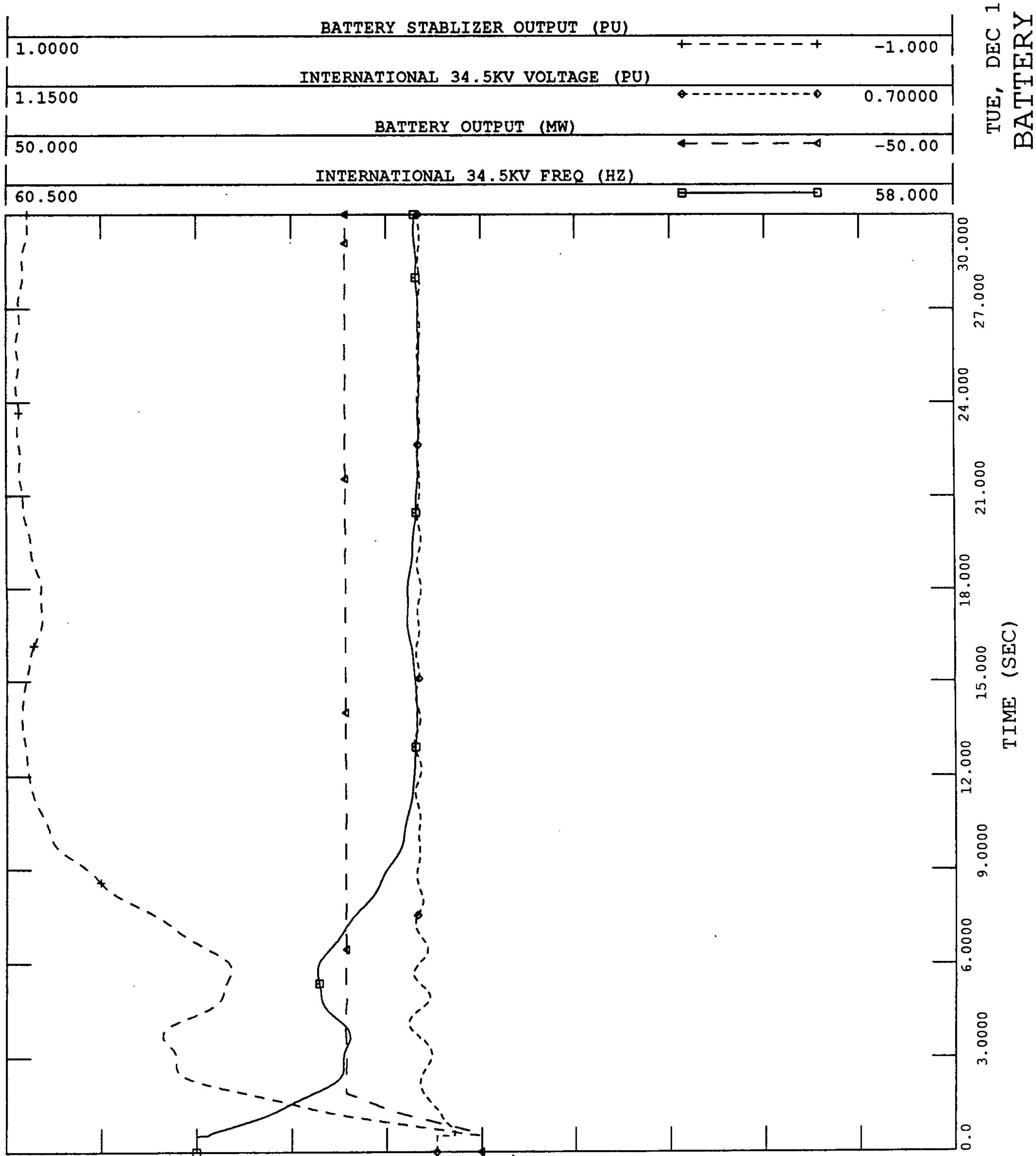


E-3

1991 WINTER PEAK LOAD. AMLP #8 IS OFF, AMLP #1 & #5 ARE ON.
15 MVA BATTERY AT INTL 34.5KV, 0 MW OUTPUT. GOVS DISABLED.
TRIP BELUGA #8 AT 54MW AT T=0.5 SECONDS. 0.5% DROOP.
LOAD SHED RELAYS AT BUS 204 ACTIVATED.

FILE: ~~AM15-1HL~~.CHN

AML15-005

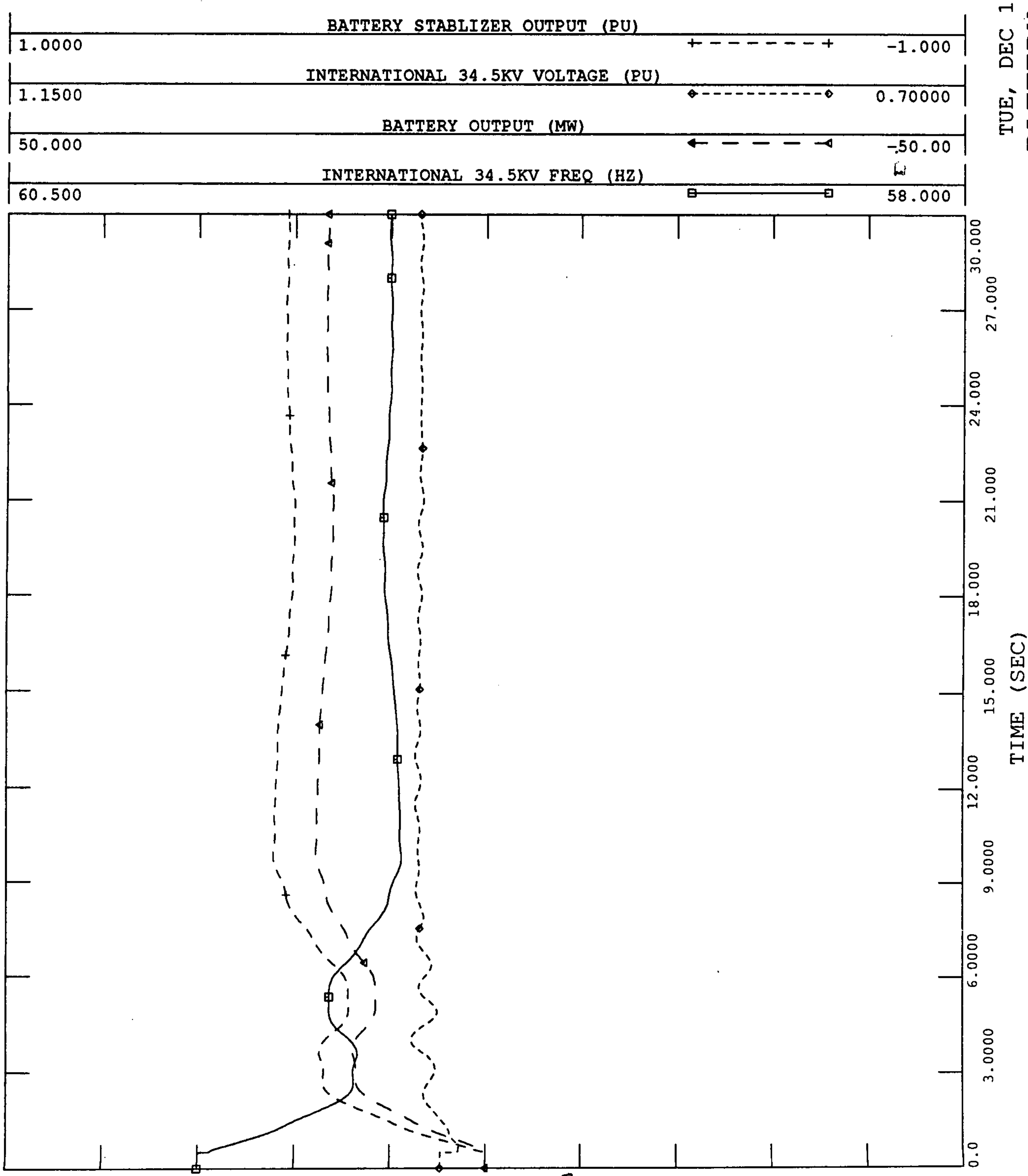


E-4

1991 WINTER PEAK LOAD. AMLP #8 IS OFF, AMLP #1 & #5 ARE ON.
20 MVA BATTERY AT INTL 34.5KV, 0 MW OUTPUT. GOVS DISABLED.
TRIP BELUGA #8 AT 54MW AT T=0.5 SECONDS. [redacted]% DROOP.
LOAD SHED RELAYS AT BUS 204 ACTIVATED.

FILE: ~~AM20-50L~~.CHN
AML20-01

TUE, DEC 17 1991 09:07
BATTERY RESPONSE

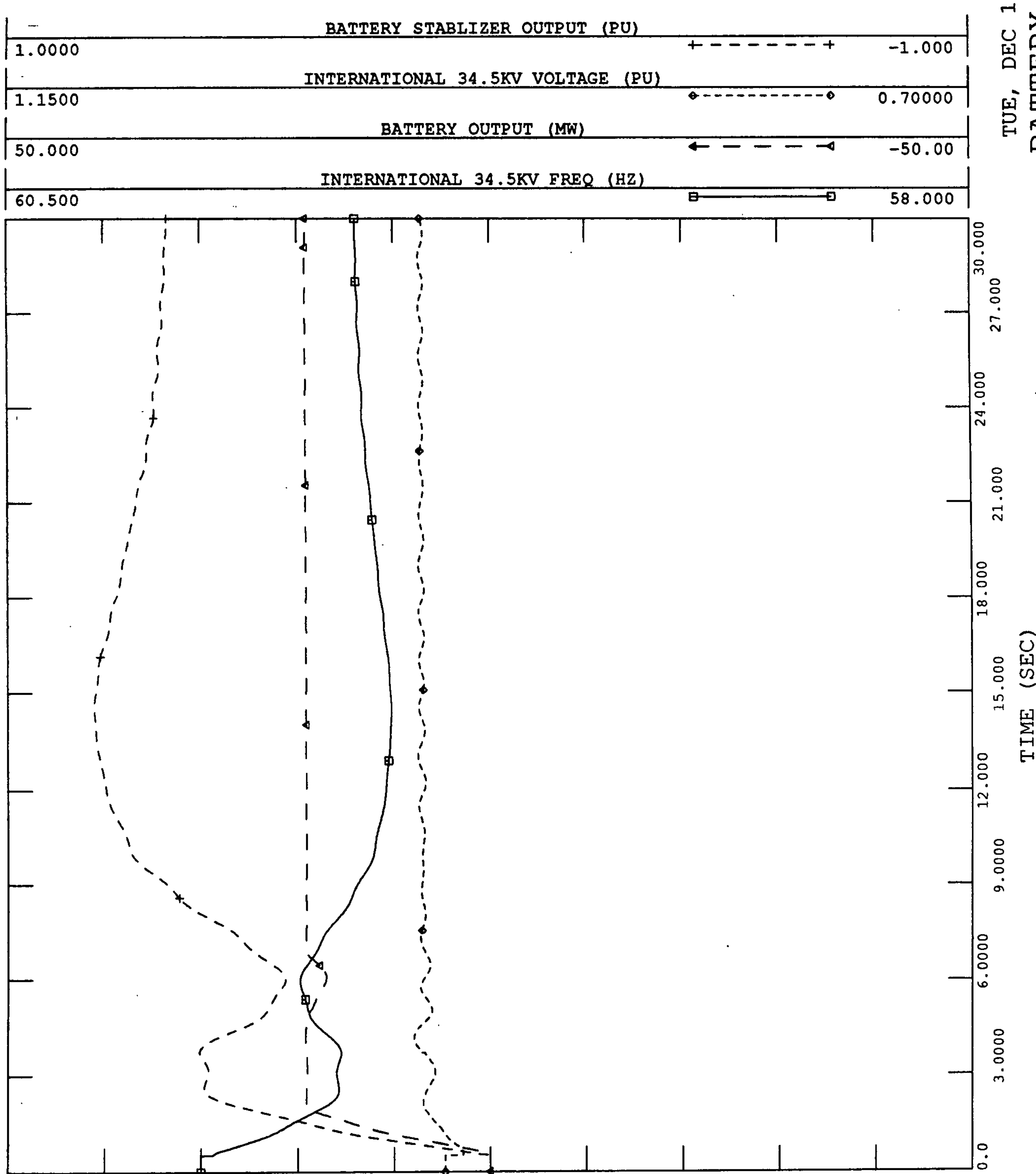


E-5

1991 WINTER PEAK LOAD. AMLP #8 IS OFF, AMLP #1 & #5 ARE ON.
20 MVA BATTERY AT INTL 34.5KV, 0 MW OUTPUT. GOVS DISABLED.
TRIP BELUGA #8 AT 54MW AT T=0.5 SECONDS.0.5% DROOP.
LOAD SHED RELAYS AT BUS 204 ACTIVATED.
FILE: ~~AM20-1HL~~.CHN

AML20-005

TUE, DEC 17 1991 09:14
BATTERY RESPONSE



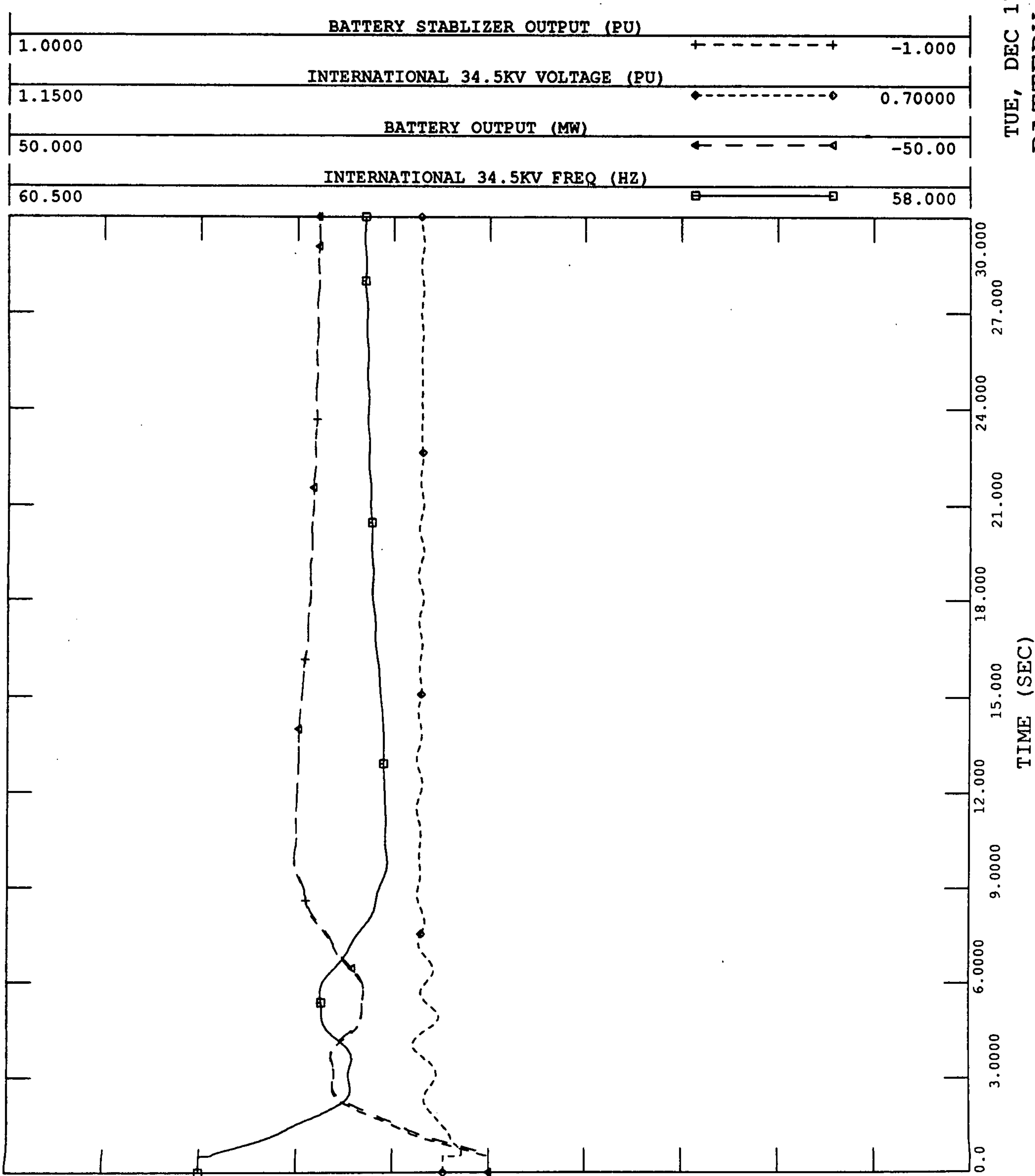
1991 WINTER PEAK LOAD. AMLP #8 IS OFF, AMLP #1 & #5 ARE ON.
25 MVA BATTERY AT INTL 34.5KV, 0 MW OUTPUT. GOVS DISABLED.
TRIP BELUGA #8 AT 54MW AT T=0.5 SECONDS. [redacted]% DROOP.
LOAD SHED RELAYS AT BUS 204 ACTIVATED.

FILE: ~~AM25-50L~~.CHN

AML25-01

TUE, DEC 17 1991 09:09

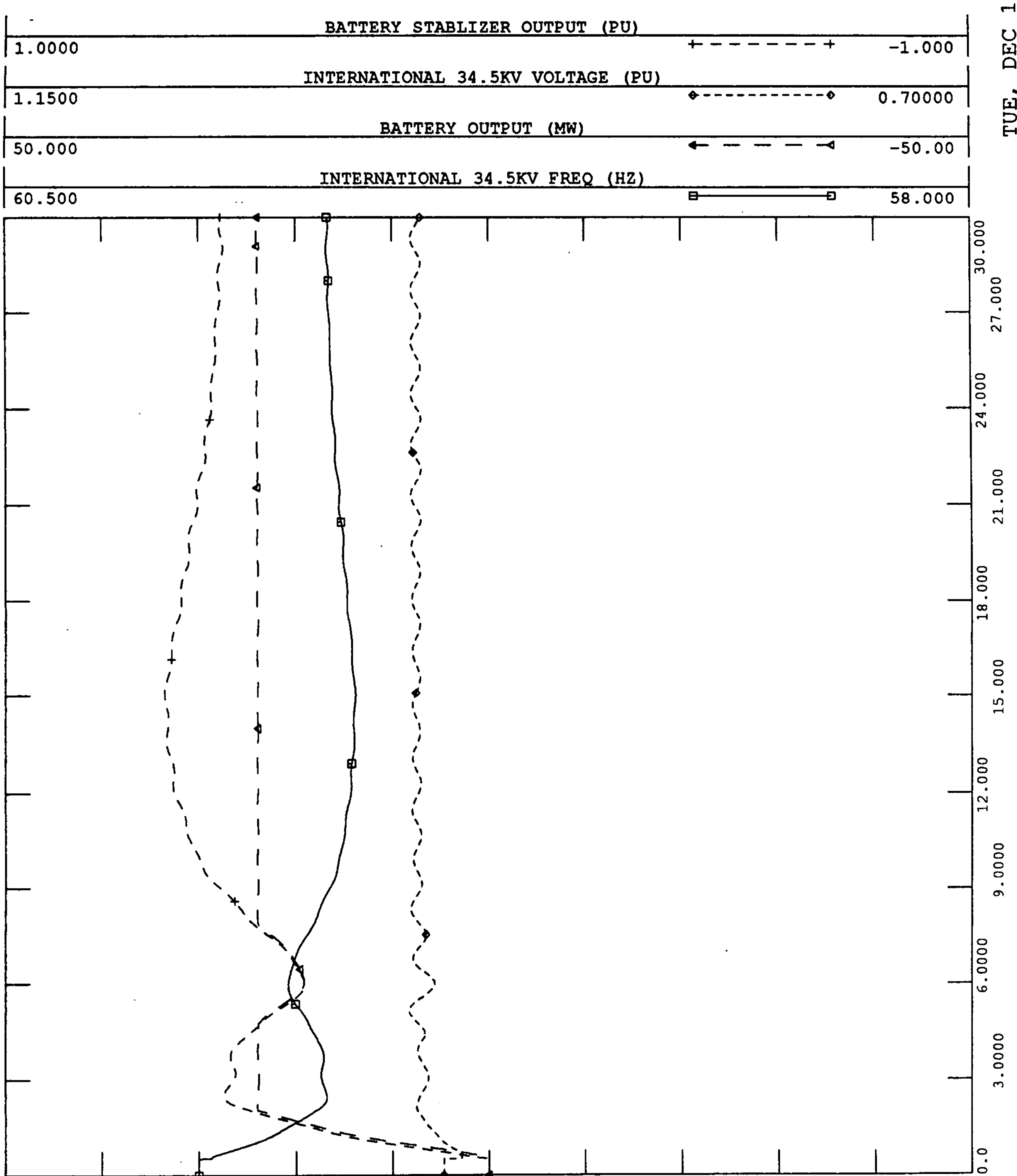
BATTERY RESPONSE



1991 WINTER PEAK LOAD. AMLP #8 IS OFF, AMLP #1 & #5 ARE ON.
25 MVA BATTERY AT INTL 34.5KV, 0 MW OUTPUT. GOVS DISABLED.
TRIP BELUGA #8 AT 54MW AT T=0.5 SECONDS.0.5% DROOP.
LOAD SHED RELAYS AT BUS 204 ACTIVATED.
FILE: ~~AM25-1HL~~.CHN

AmL25-005

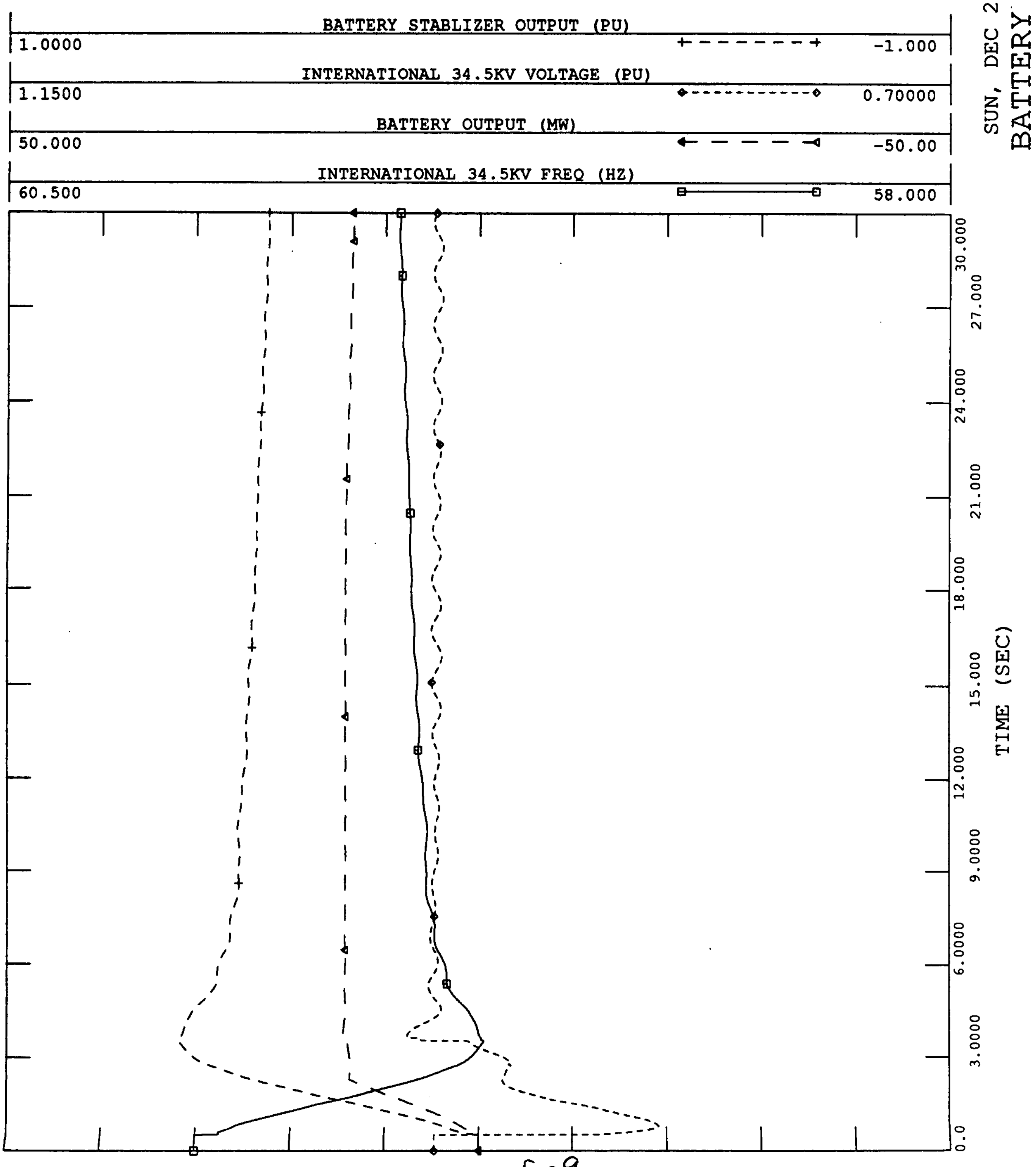
TUE, DEC 17 1991 09:12
BATTERY RESPONSE



E-8

1991 WINTER PEAK LOAD. AMLP #8 IS OFF, AMLP #1 & #5 ARE ON.
15 MVA BATTERY AT INTL 34.5KV, 0 MW OUTPUT. GOVS DISABLED.
TRIP ~~BELUGA #8~~ UNIT #6,7 AT [redacted] 95 MW AT T=0.5 SECONDS. 1% DROOP.

FILE: S3U7-15.CHN

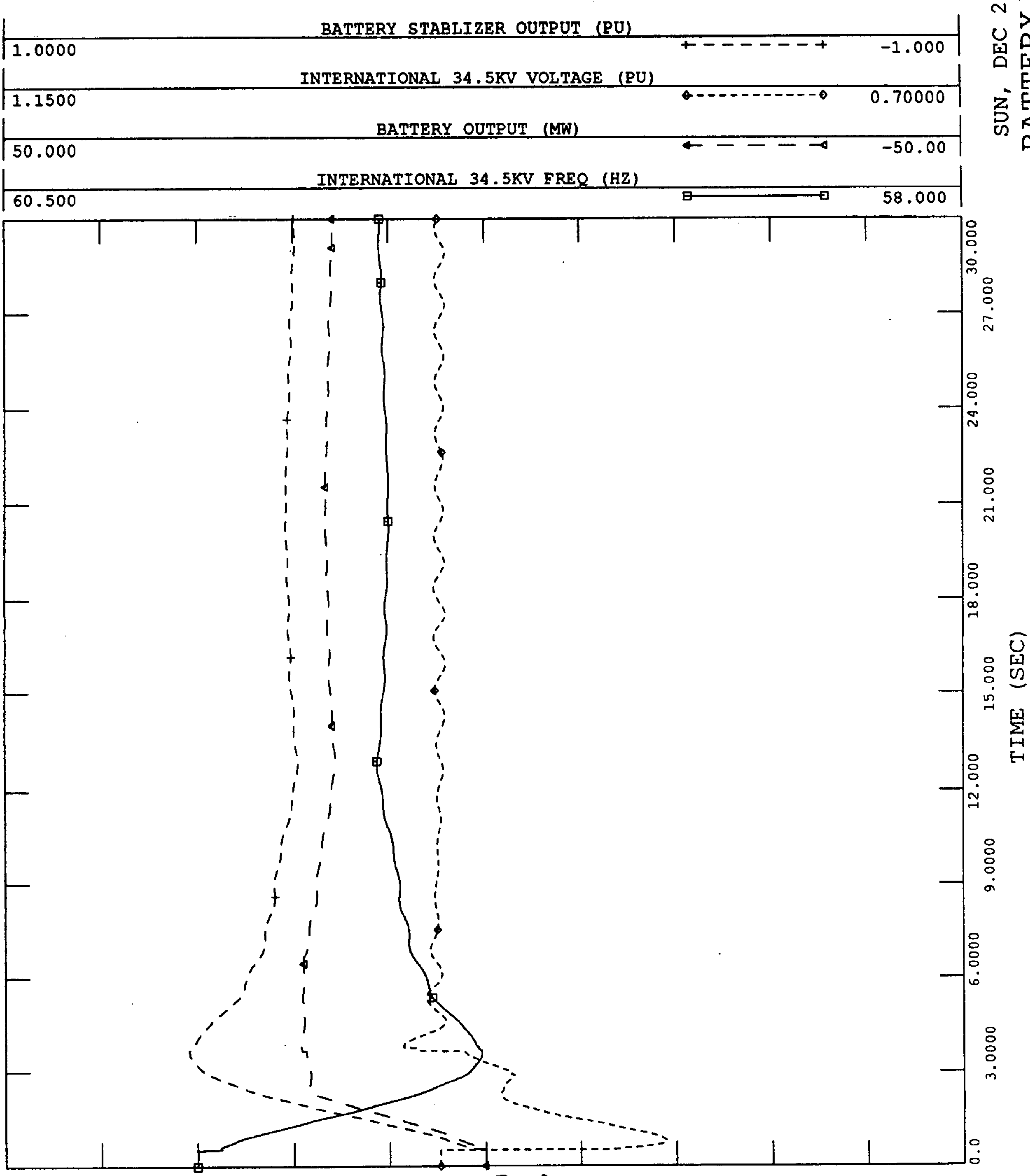


1991 WINTER PEAK LOAD. AMLP #8 IS OFF, AMLP #1 & #5 ARE ON.
20 MVA BATTERY AT INTL 34.5KV, 0 MW OUTPUT. GOVS DISABLED.
TRIP ~~BELUGA #8~~ UNIT #6,7 AT ~~54~~ 95 MW AT T=0.5 SECONDS. 1% DROOP

FILE: S3U7-20.CHN

SUN, DEC 29 1991 12:32

BATTERY RESPONSE



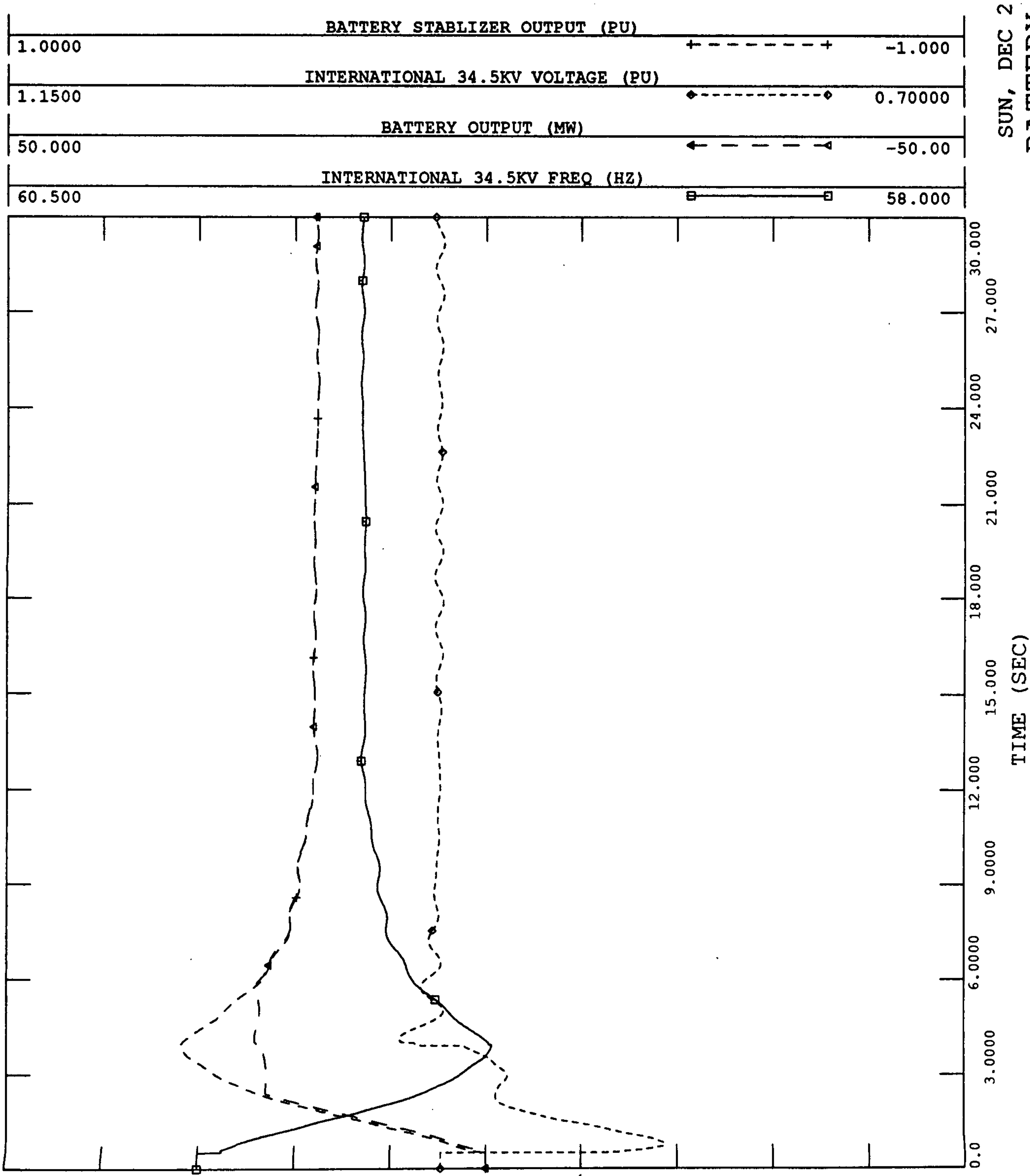
E-10

1991 WINTER PEAK LOAD. AMLP #8 IS OFF, AMLP #1 & #5 ARE ON.
25 MVA BATTERY AT INTL 34.5KV, 0 MW OUTPUT. GOVS DISABLED.
TRIP ~~BELUGA #8~~ UNIT #6,7 AT ~~54~~ 95 MW AT T=0.5 SECONDS. 1% DROOP

FILE: S3U7-25.CHN

SUN, DEC 29 1991 12:40

BATTERY RESPONSE

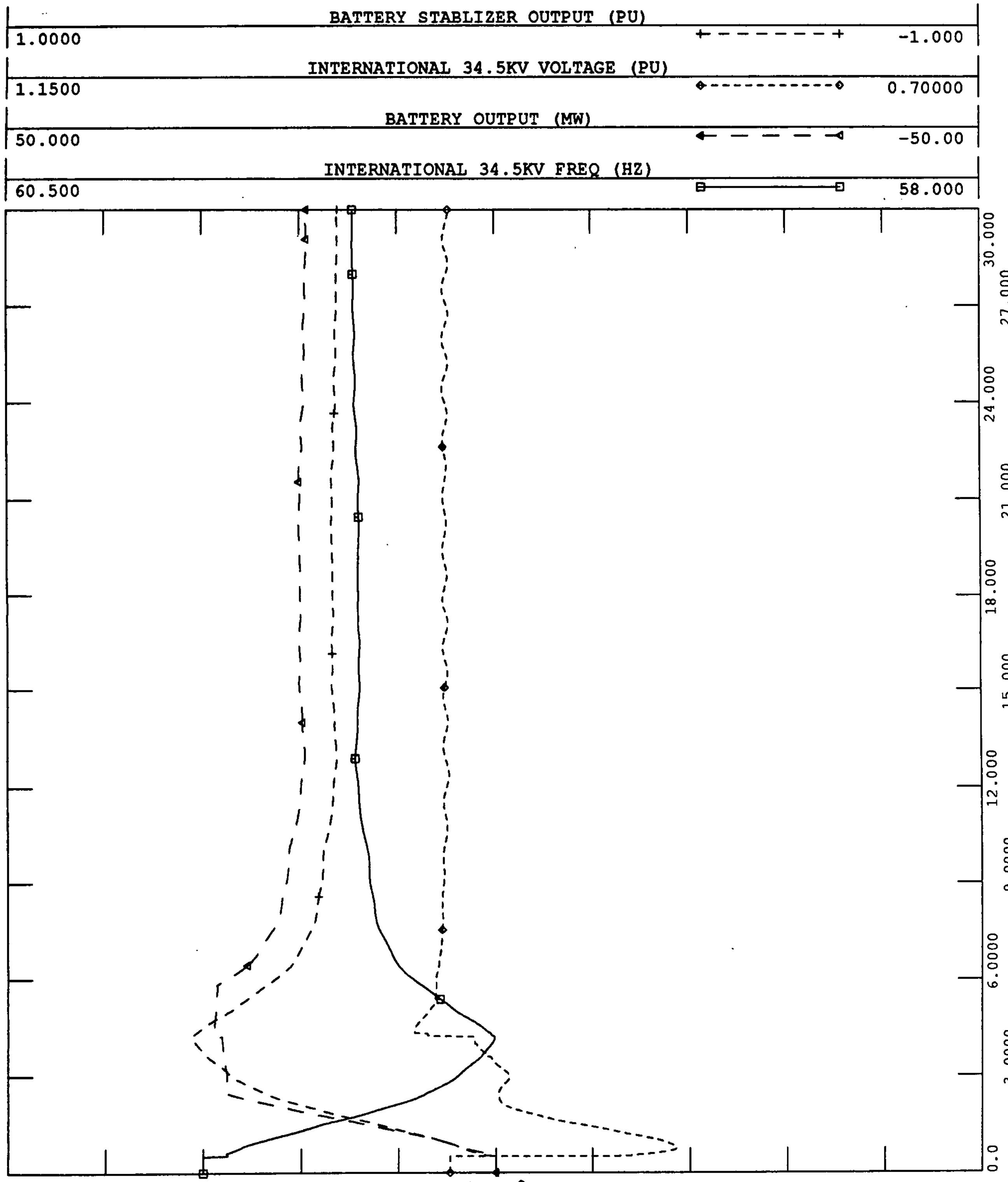


1991 WINTER PEAK LOAD. AMLP #8 IS OFF, AMLP #1 & #5 ARE ON.
30 BATTERY AT INTL 34.5KV. 1% DROOP
TRIP UNIT # 6 & 7 AT 95 MW AT T=0.5 SECONDS.

FILE: S3U7-30.CHN

FRI, DEC 27 1991 09:13

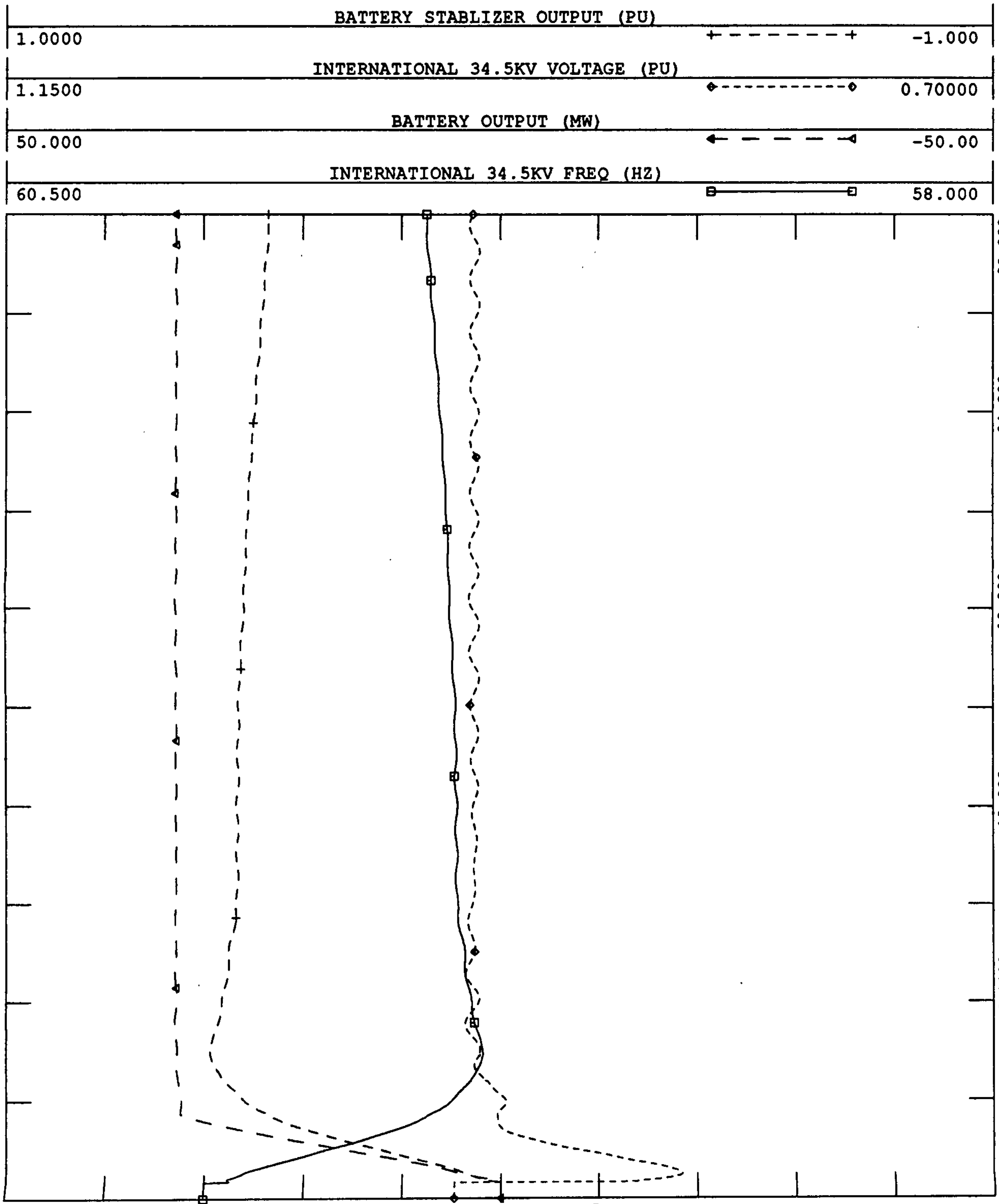
BATTERY RESPONSE



1991 WINTER PEAK LOAD. AMLP #8 IS OFF, AMLP #1 & #5 ARE ON.
35 BATTERY AT INTL 34.5KV. 1% DROOP
TRIP UNIT #6 & 7 AT ~~50~~ 95 MW AT T=0.5 SECONDS.

FILE: S3U7-35.CHN

MON, DEC 30 1991 11:49
BATTERY RESPONSE

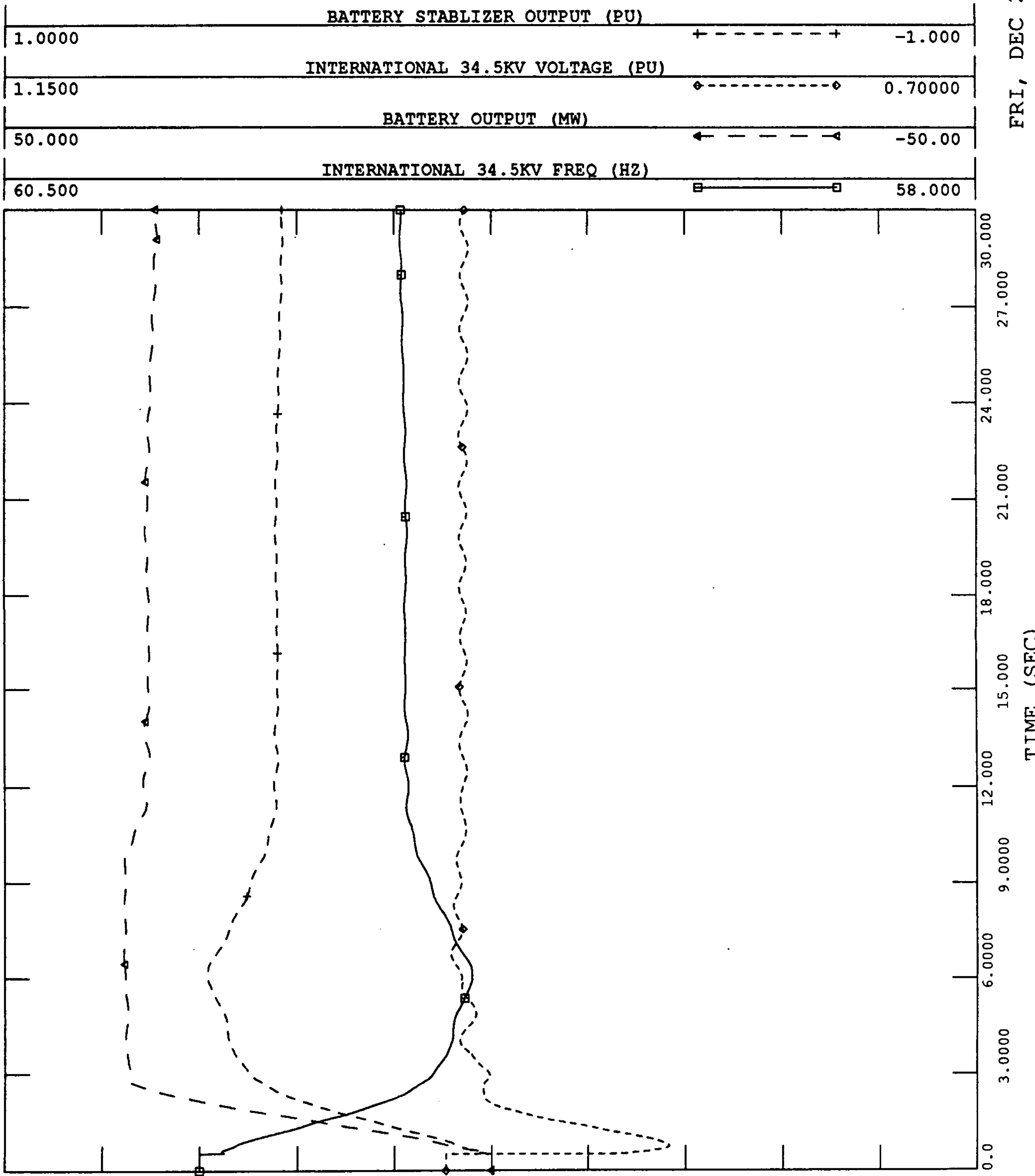


1991 WINTER PEAK LOAD. AMLP #8 IS OFF, AMLP #1 & #5 ARE ON.
40 BATTERY AT INTL 34.5KV. 1% DROOP
TRIP UNIT # 6 & 7 AT 95 MW AT T=0.5 SECONDS.

FILE: S3U7-40.CHN

FRI, DEC 27 1991 09:16

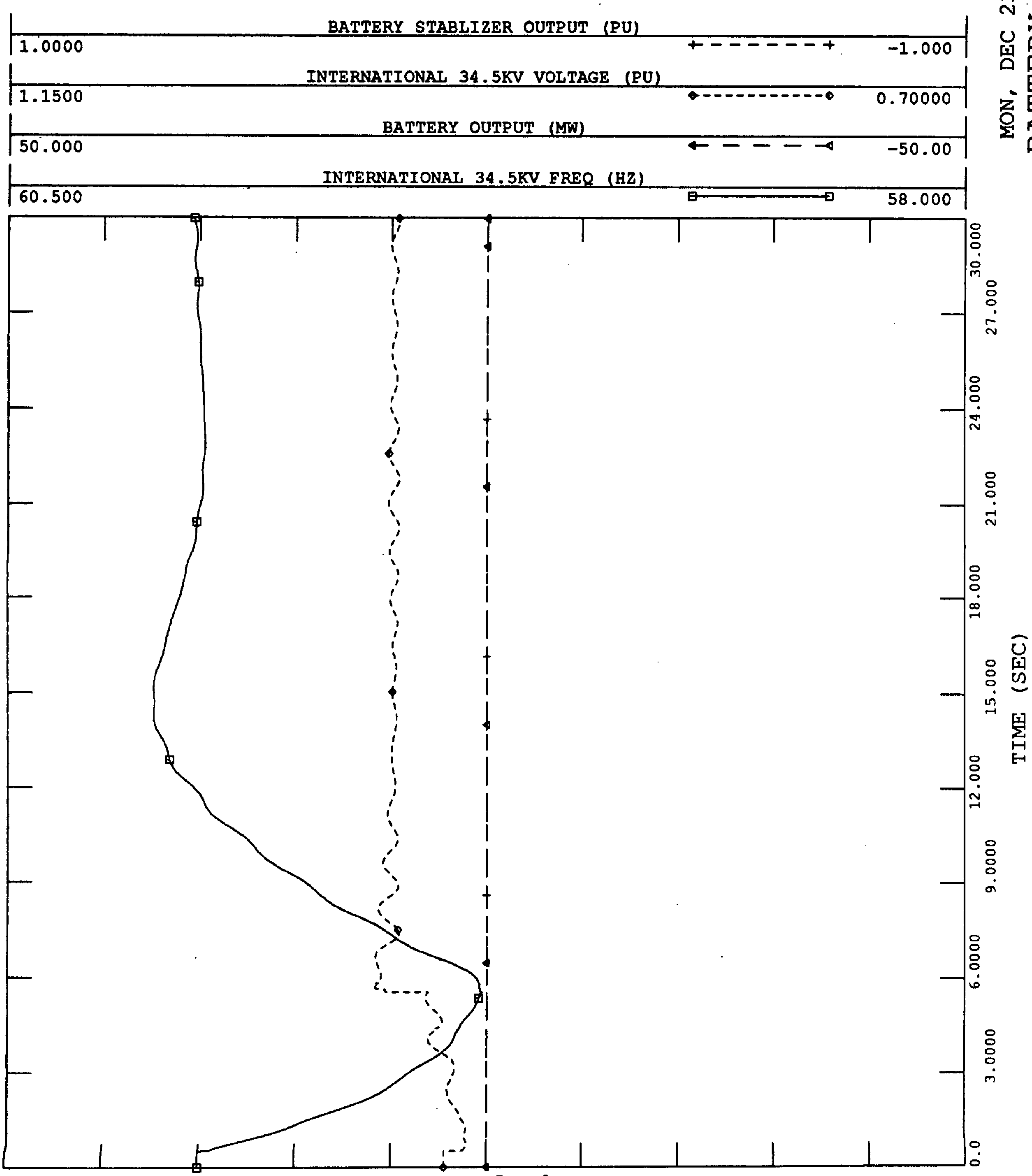
BATTERY RESPONSE



1991 WINTER PEAK LOAD. AMLP #8 IS OFF, AMLP #1 & #5 ARE ON.
NO BATTERY. GOVS DISABLED. BERNICE LAKE UNIT IS OFF.
TRIP BELUGA #8 AT 54 MW AT T=0.5 SECONDS.

FILE: CEA-00.CHN

MON, DEC 23 1991 09:04
BATTERY RESPONSE



F

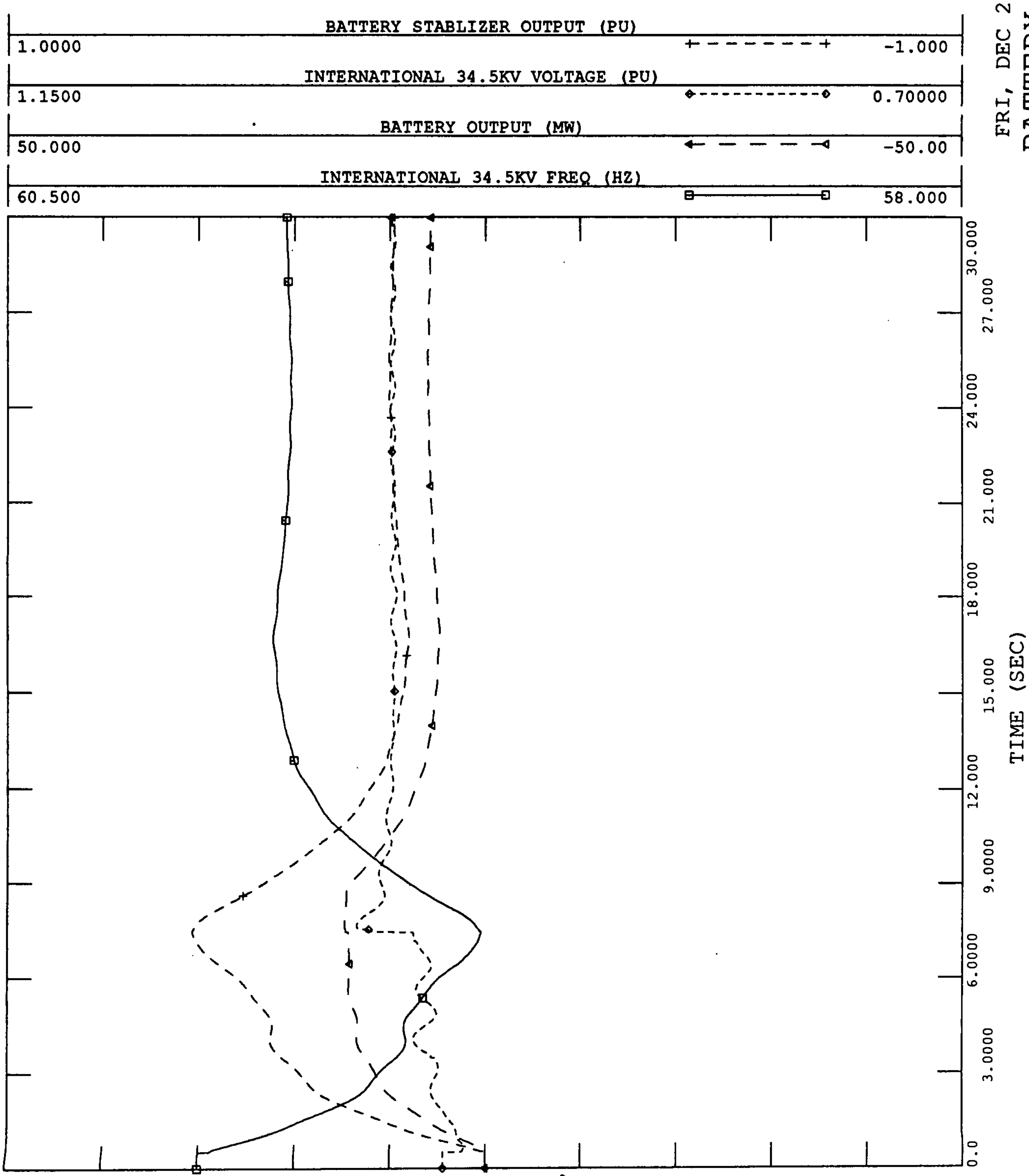
STABILITY ANALYSIS: SCENARIO 4

This appendix contains the simulations of Scenario 4. Battery sizes from 15 to 50 MW and droop settings of 0.5% and 1% were used. A simulation case was also run in which no battery was used. In this scenario, two disturbances were studied: a 54 MW loss of generation and a 95 MW loss of generation.

1991 WINTER PEAK LOAD. AMLP #8 IS OFF, AMLP #1 & #5 ARE ON.
15 MVA BATTERY, 0 MW OUTPUT. GOVS DISABLED. BERNICE IS OFF.
TRIP BELUGA #8 AT 54 MW AT T=0.5 SECONDS. 1% DROOP.

FILE: CEA15-01.CHN

FRI, DEC 27 1991 13:29
BATTERY RESPONSE

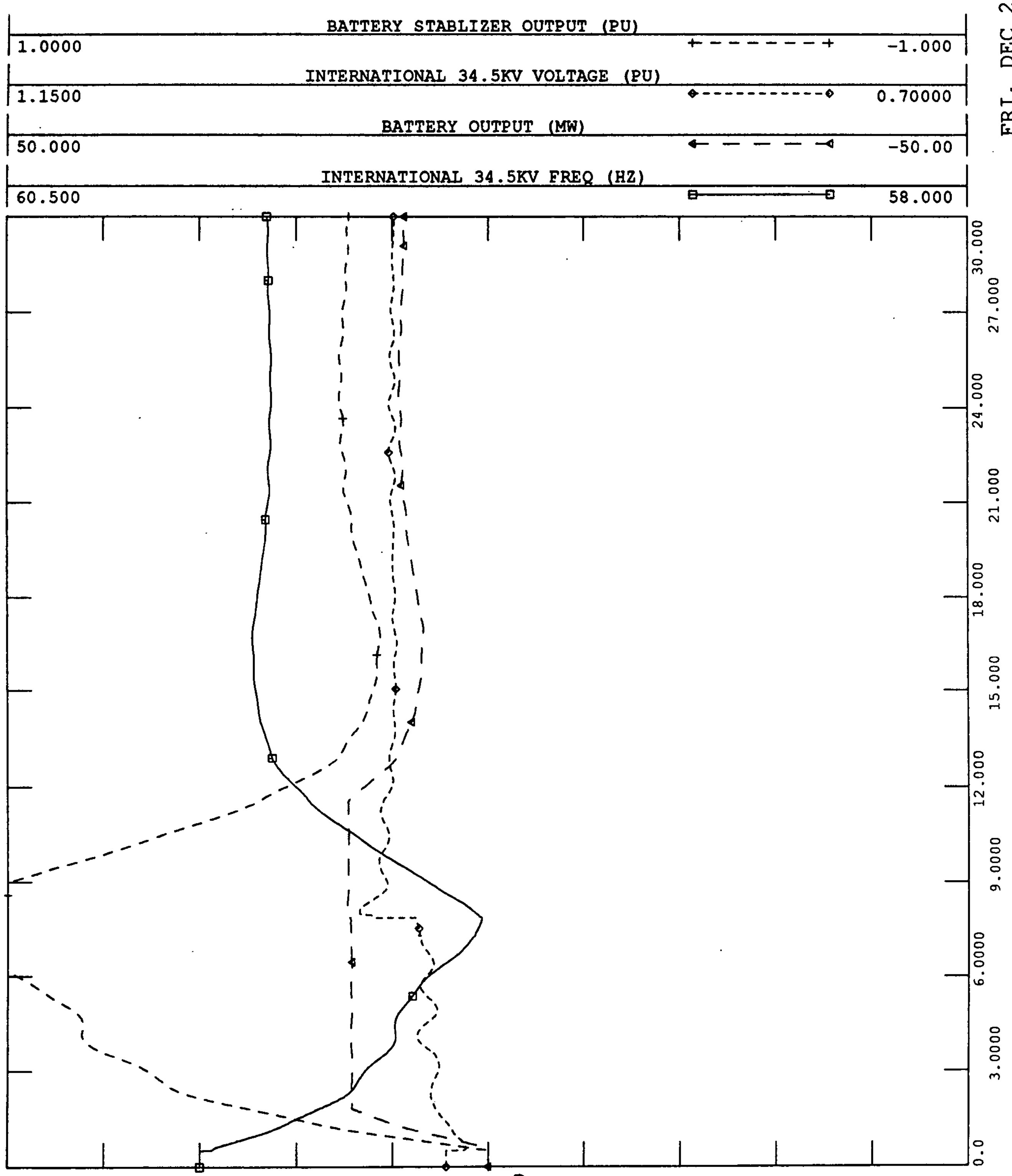


F-2

1991 WINTER PEAK LOAD. AMLP #8 IS OFF, AMLP #1 & #5 ARE ON.
15 MVA BATTERY, 0 MW OUTPUT. GOVS DISABLED. BERNICE IS OFF.
TRIP BELUGA #8 AT 54 MW AT T=0.5 SECONDS. 0.5% DROOP

FILE: CEA15-05.CHN

FRI, DEC 27 1991 13:31
BATTERY RESPONSE



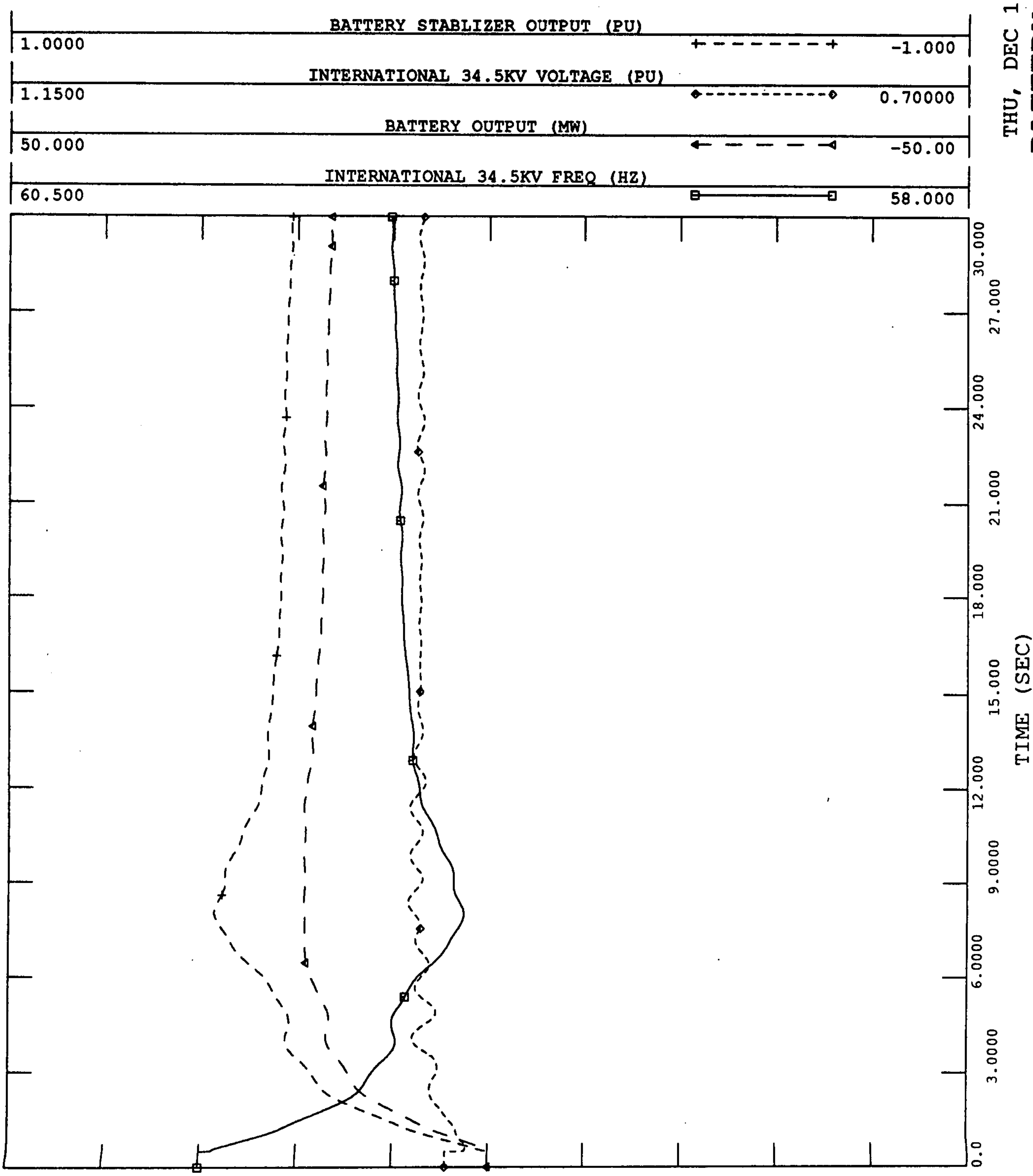
F-3

1991 WINTER PEAK LOAD. AMLP #8 IS OFF, AMLP #1 & #5 ARE ON.
20 MVA BATTERY, 0 MW OUTPUT. GOVS DISABLED. BERNICE IS OFF.
TRIP BELUGA #8 AT 54MW AT T=0.5 SECONDS. 1% DROOP.

FILE: CEA20-01.CHN

THU, DEC 19 1991 12:03

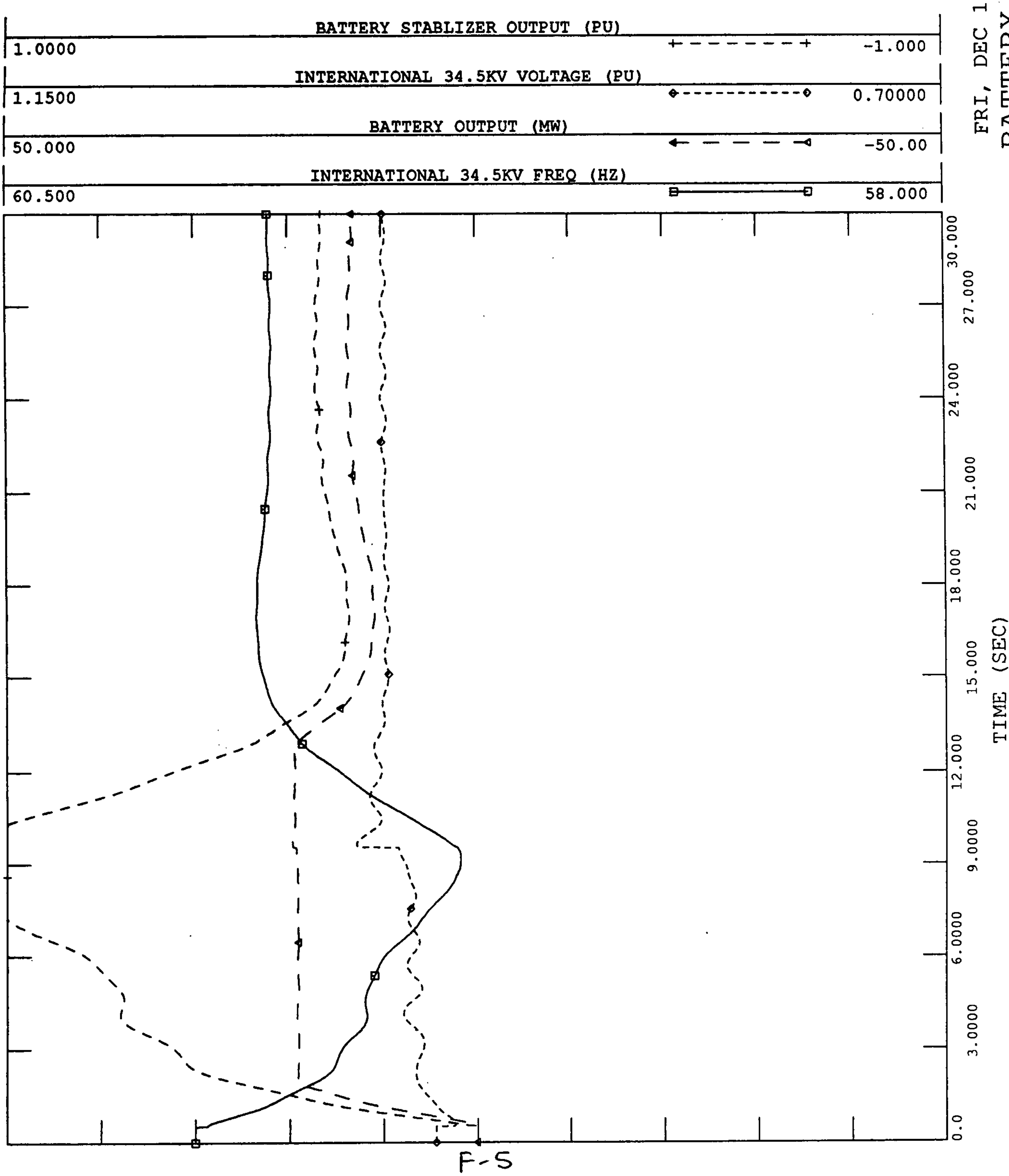
BATTERY RESPONSE



F-4

1991 WINTER PEAK LOAD. AMLP #8 IS OFF, AMLP #1 & #5 ARE ON.
20 MVA BATTERY, 0 MW OUTPUT. GOVS DISABLED. BERNICE IS OFF.
TRIP BELUGA #8 AT 54MW AT T=0.5 SECONDS. 0.5% DROOP.
LOAD SHED RELAYS AT BUS 204 ACTIVATED. ~~NO SPIN IN GEA~~.
FILE: CEA20-~~1M~~ 005 .CHN

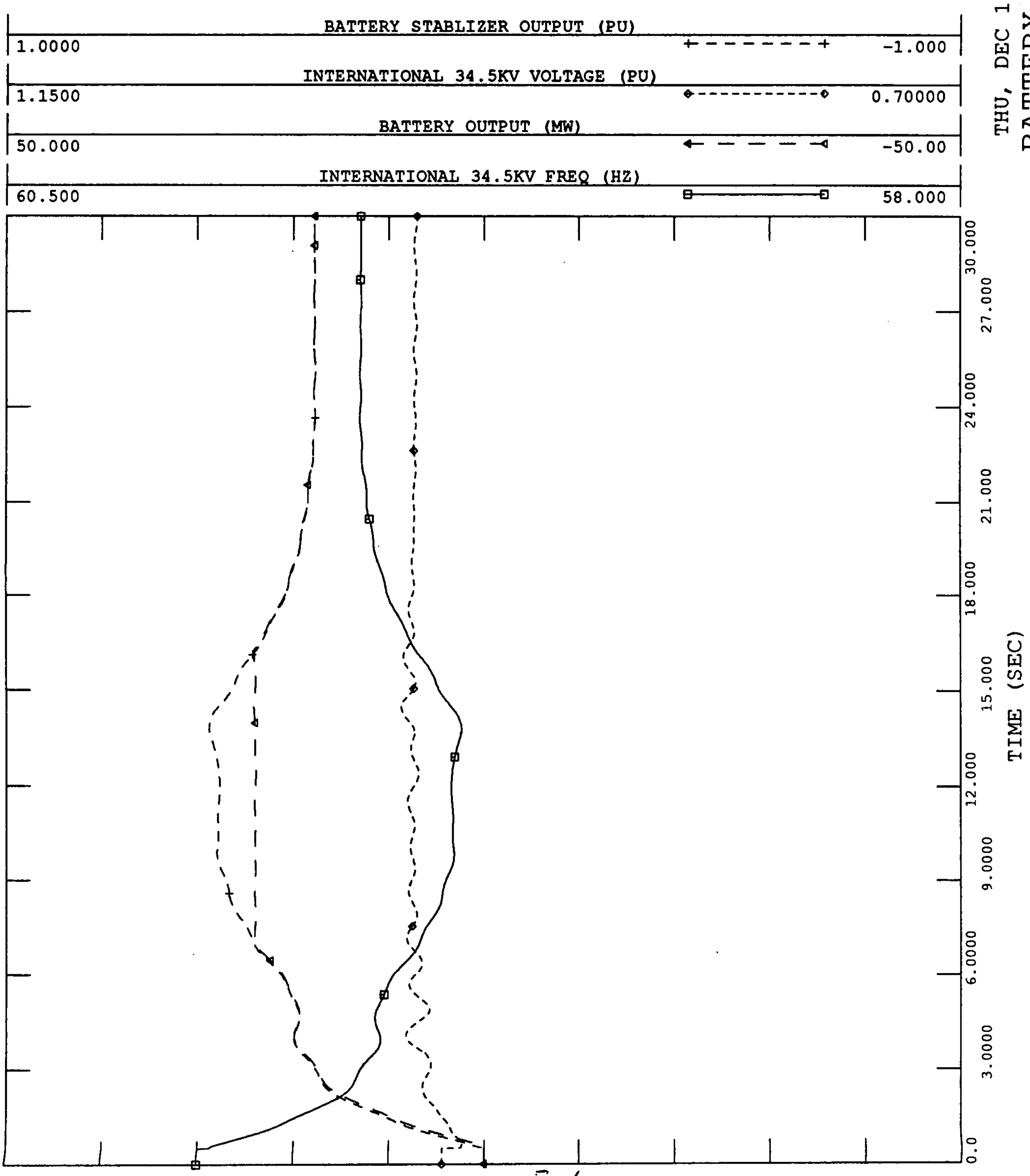
FRI, DEC 13 1991 12:07
BATTERY RESPONSE



1991 WINTER PEAK LOAD. AMLP #8 IS OFF, AMLP #1 & #5 ARE ON.
25 MVA BATTERY, 0 MW OUTPUT. GOVS DISABLED. BERNICE IS OFF.
TRIP BELUGA #8 AT 54MW AT T=0.5 SECONDS. 1% DROOP.

FILE: CEA25-01.CHN

THU, DEC 19 1991 12:05
BATTERY RESPONSE

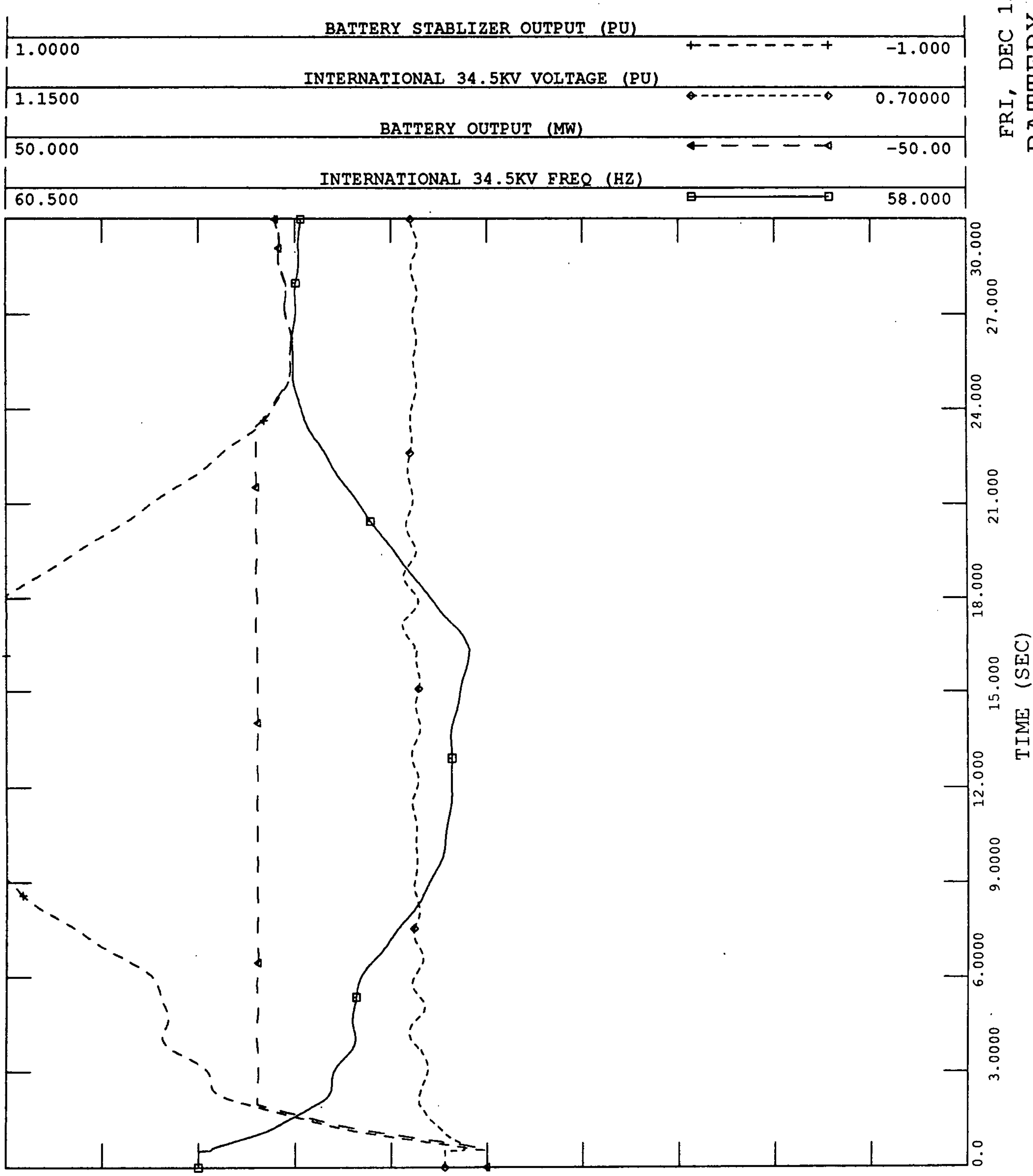


1991 WINTER PEAK LOAD. AMLP #8 IS OFF, AMLP #1 & #5 ARE ON.
25 MVA BATTERY, 0 MW OUTPUT. GOVS DISABLED. BERNICE IS OFF.
TRIP BELUGA #8 AT 54MW AT T=0.5 SECONDS.0.5% DROOP.
LOAD SHED RELAYS AT BUS 204 ACTIVATED. [redacted].

FILE: CEA25-~~1H~~.CHN
005

FRI, DEC 13 1991 12:09

BATTERY RESPONSE

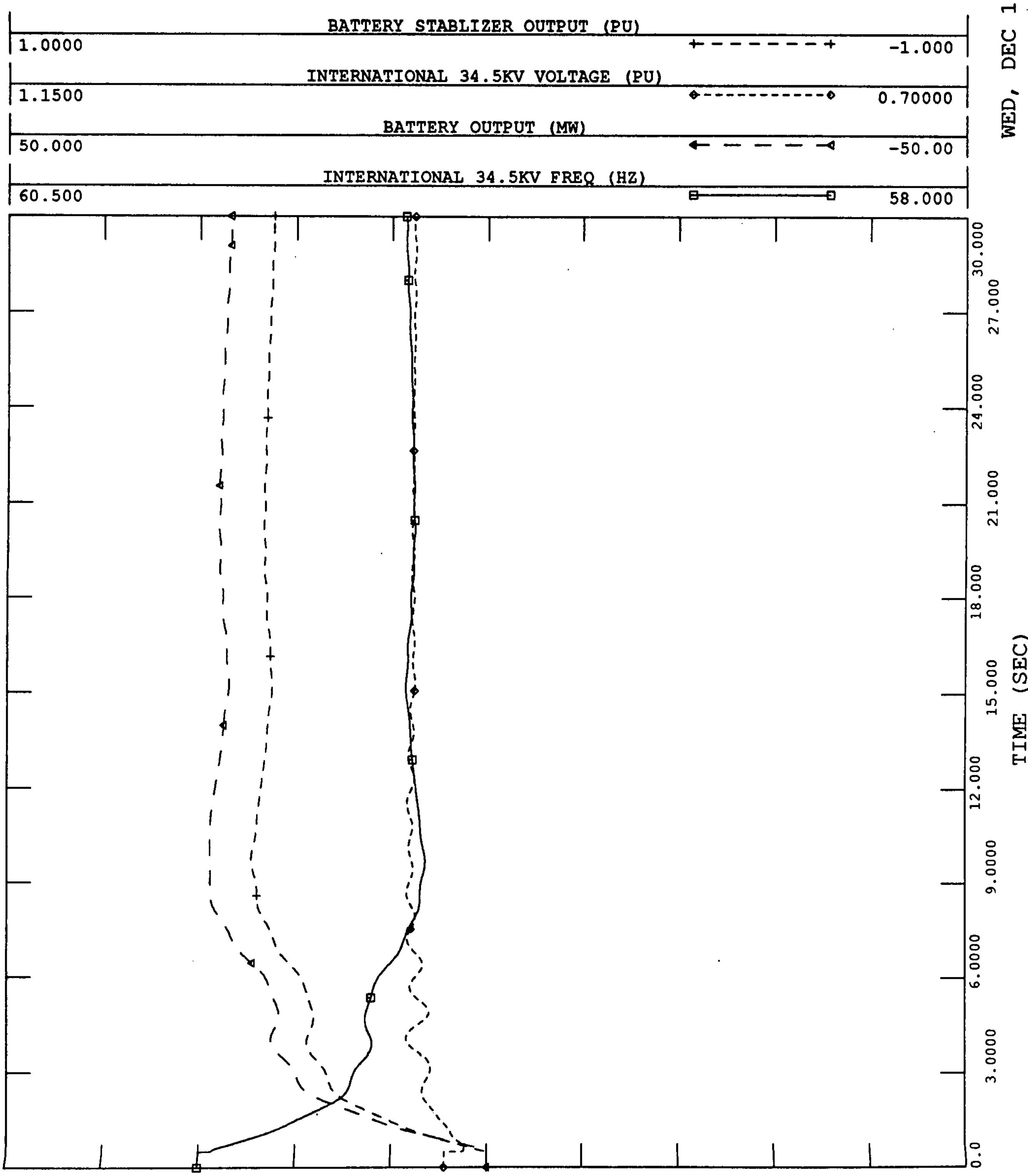


1991 WINTER PEAK LOAD. AMLP #8 IS OFF, AMLP #1 & #5 ARE ON.
30 MVA BATTERY, 0 MW OUTPUT. GOVS DISABLED. BERNICE IS OFF.
TRIP BELUGA #8 AT 54MW AT T=0.5 SECONDS. 1% DROOP.

FILE: CEA30-01.CHN

WED, DEC 18 1991 09:05

BATTERY RESPONSE



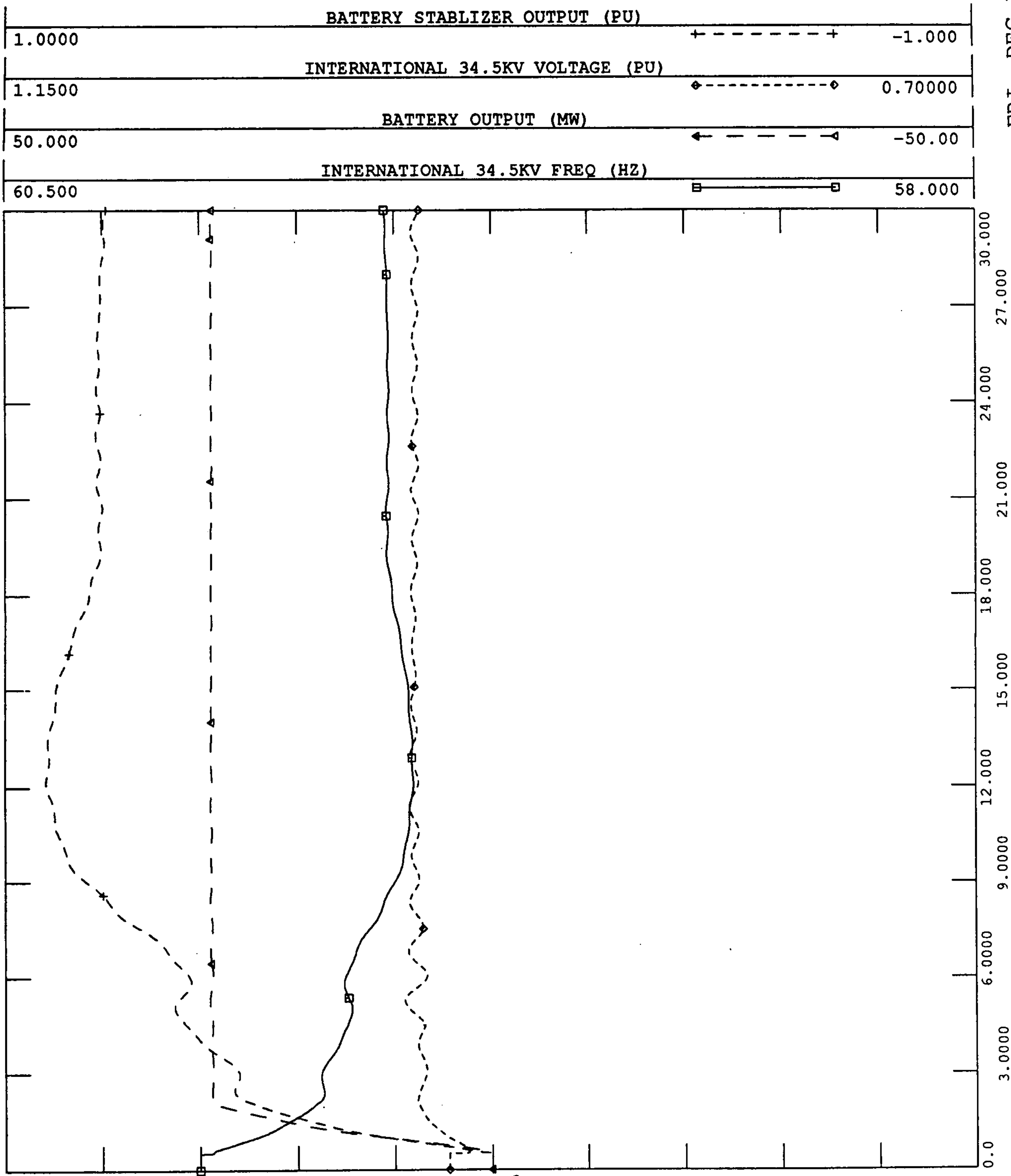
F-8

1991 WINTER PEAK LOAD. AMLP #8 IS OFF, AMLP #1 & #5 ARE ON.
30 MVA BATTERY, 0 MW OUTPUT. GOVS DISABLED. BERNICE IS OFF.
TRIP BELUGA #8 AT 54MW AT T=0.5 SECONDS. 0.5% DROOP.
LOAD SHED RELAYS AT BUS 204 ACTIVATED. [redacted].

FILE: CEA30-~~1M~~.CHN
005

FRI, DEC 13 1991 09:32

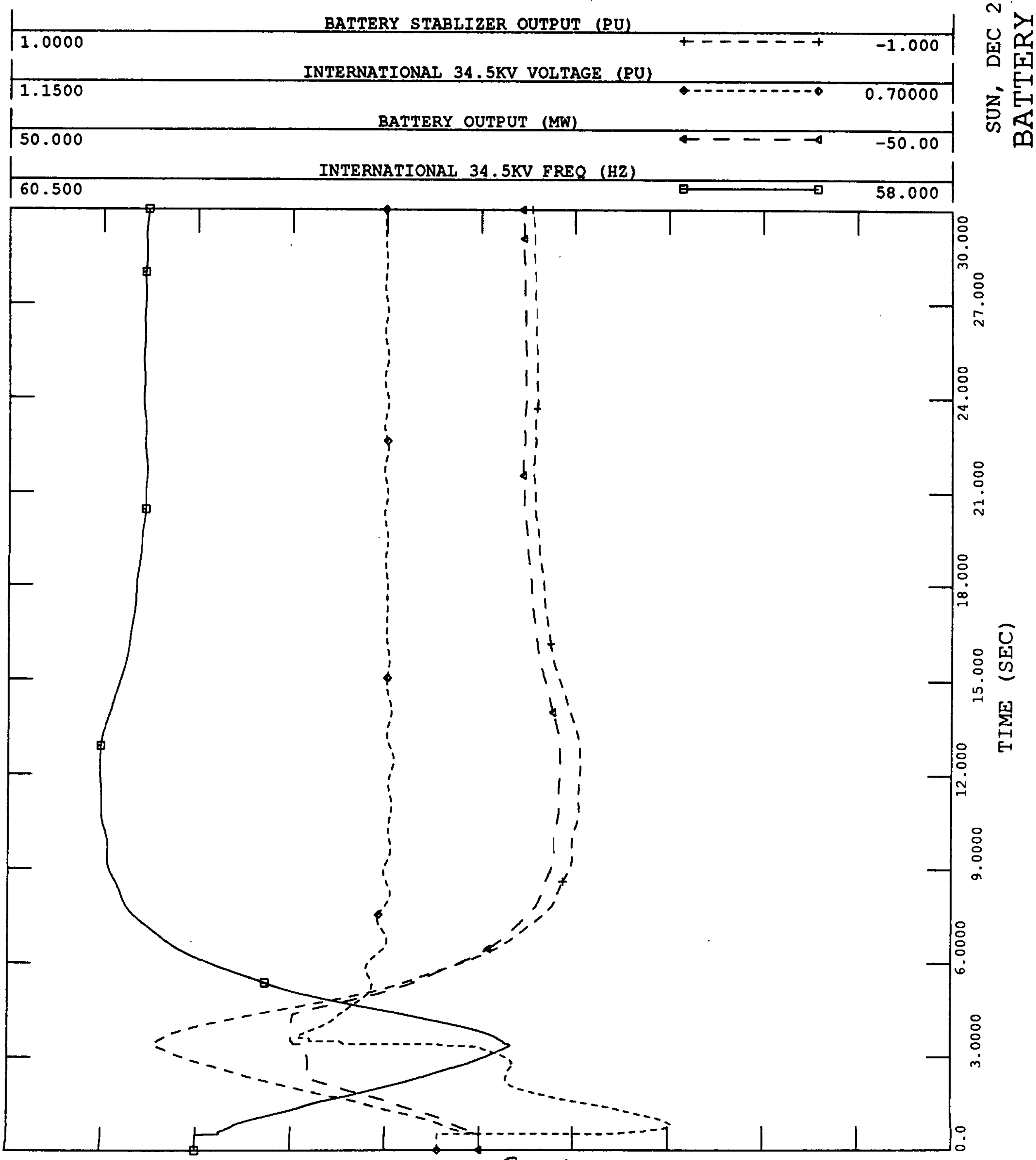
BATTERY RESPONSE



F-9

1991 WINTER PEAK LOAD. AMLP #8 IS OFF, AMLP #1 & #5 ARE ON.
20 MVA BATTERY, 0 MW OUTPUT. GOVS DISABLED. BERNICE IS OFF.
TRIP ~~BELUGA #8~~ AT ~~54~~ MW AT T=0.5 SECONDS. (1% DROOP
UNIT #6,7 95

FILE: S4U7-20.CHN

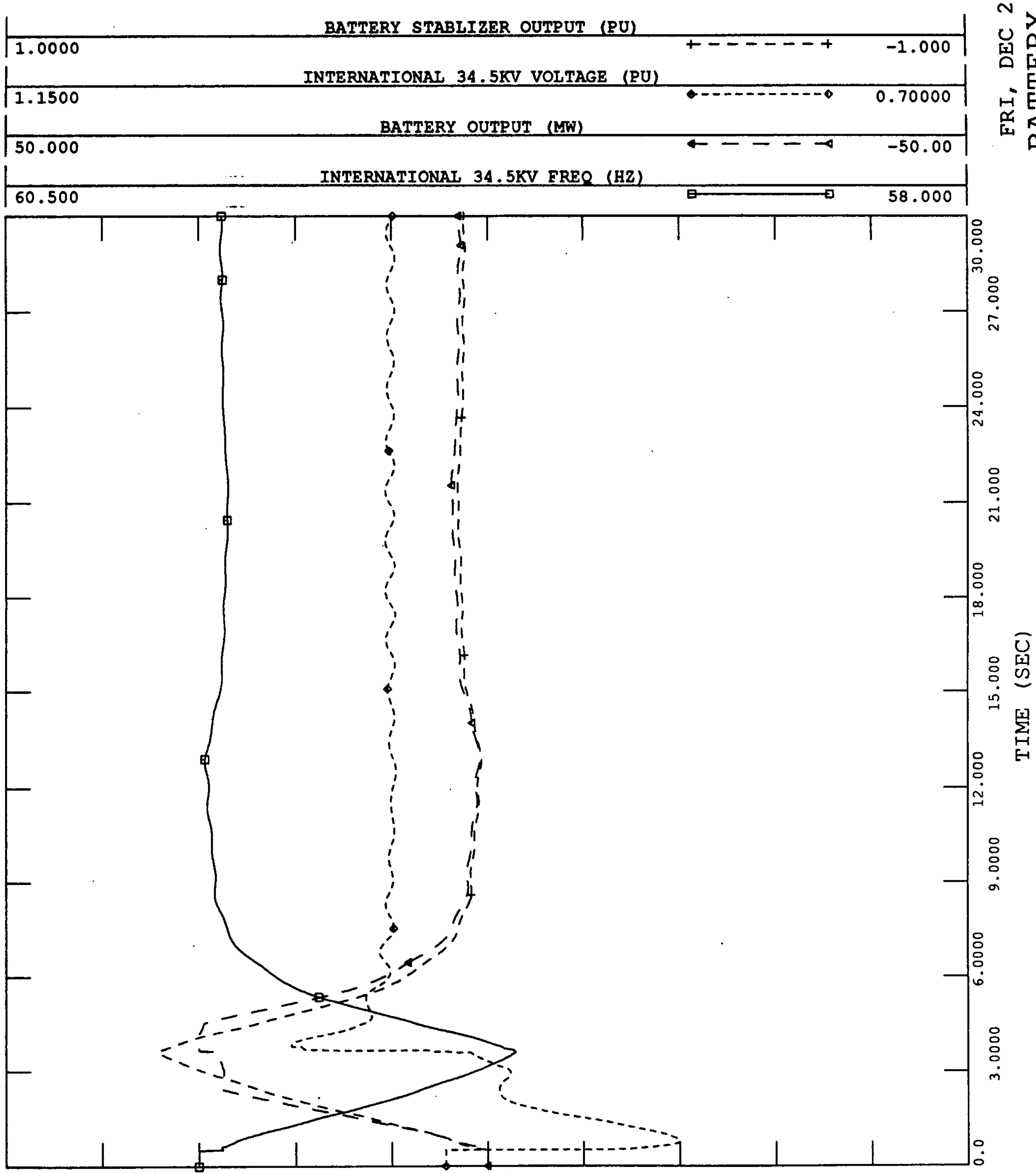


F-10

1991 WINTER PEAK LOAD. AMLP #8 IS OFF, AMLP #1 & #5 ARE ON.
30 MVA BATTERY. GOVS DISABLED. BERNICE LAKE UNIT IS OFF.
TRIP UNIT # 6 & 7 AT 95 MW AT T=0.5 SECONDS. 1% DROOP

FILE: S4U7-30.CHN

FRI, DEC 27 1991 09:20
BATTERY RESPONSE

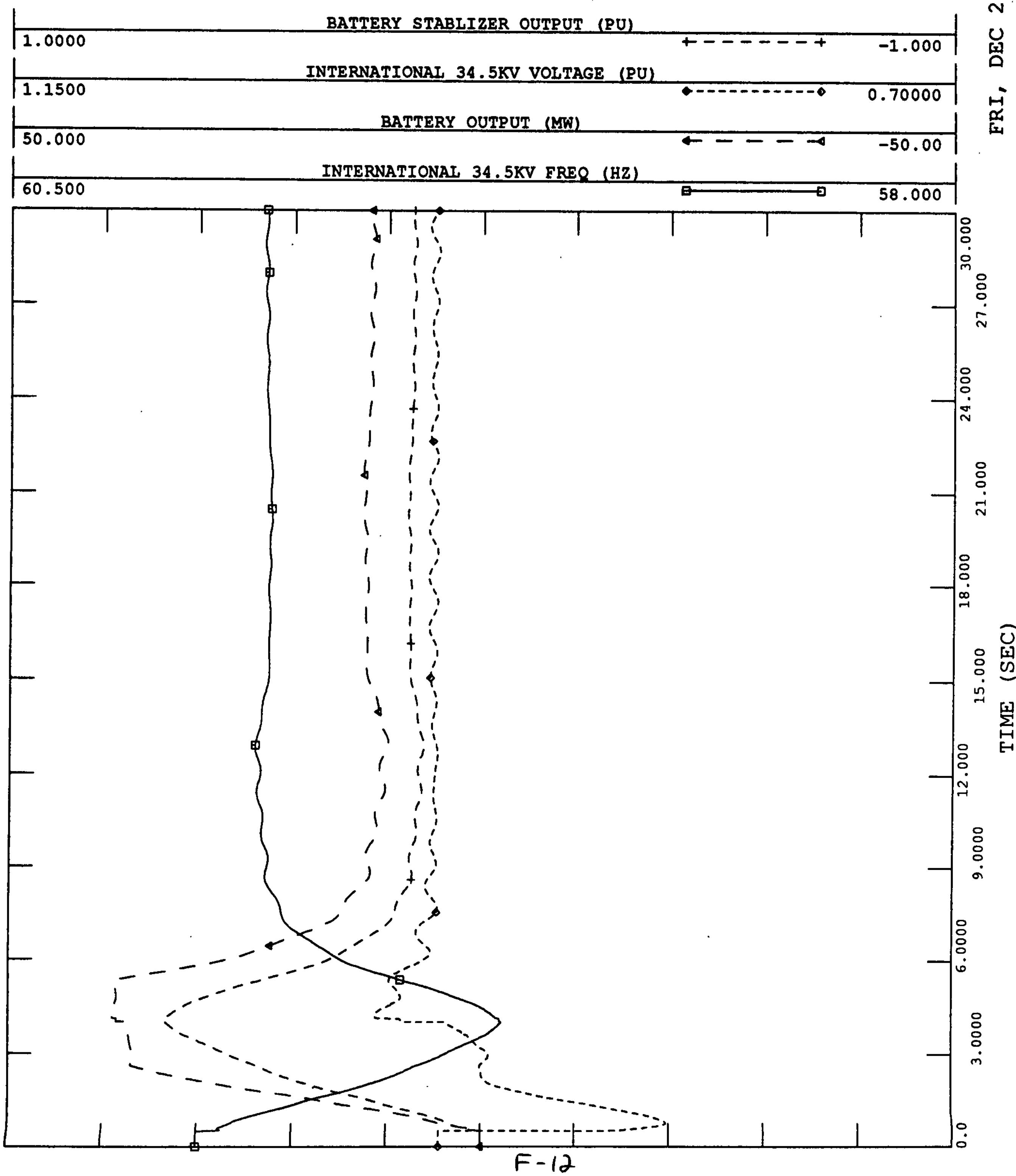


F-11

1991 WINTER PEAK LOAD. AMLP #8 IS OFF, AMLP #1 & #5 ARE ON.
40 MVA BATTERY. GOVS DISABLED. BERNICE LAKE UNIT IS OFF.
TRIP UNIT # 6 & 7 AT 95 MW AT T=0.5 SECONDS. 1% DROOP.

FILE: S4U7-40.CHN

FRI, DEC 27 1991 09:22
BATTERY RESPONSE

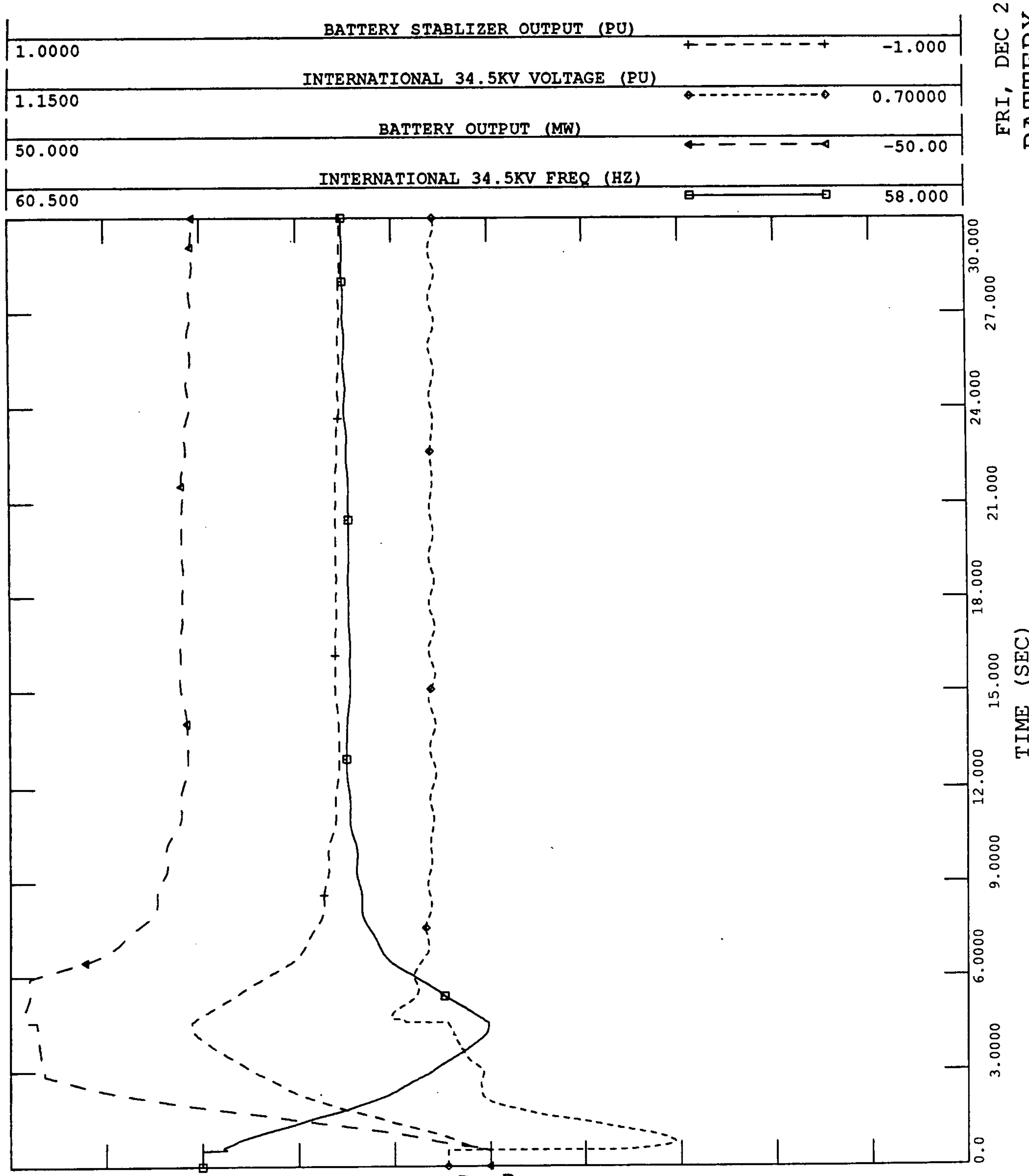


F-12

1991 WINTER PEAK LOAD. AMLP #8 IS OFF, AMLP #1 & #5 ARE ON.
50 MVA BATTERY. GOVS DISABLED. BERNICE LAKE UNIT IS OFF.
TRIP UNIT # 6 & 7 AT 95 MW AT T=0.5 SECONDS. 1% DROOP

FILE: S4U7-50.CHN

FRI, DEC 27 1991 09:25
BATTERY RESPONSE



G

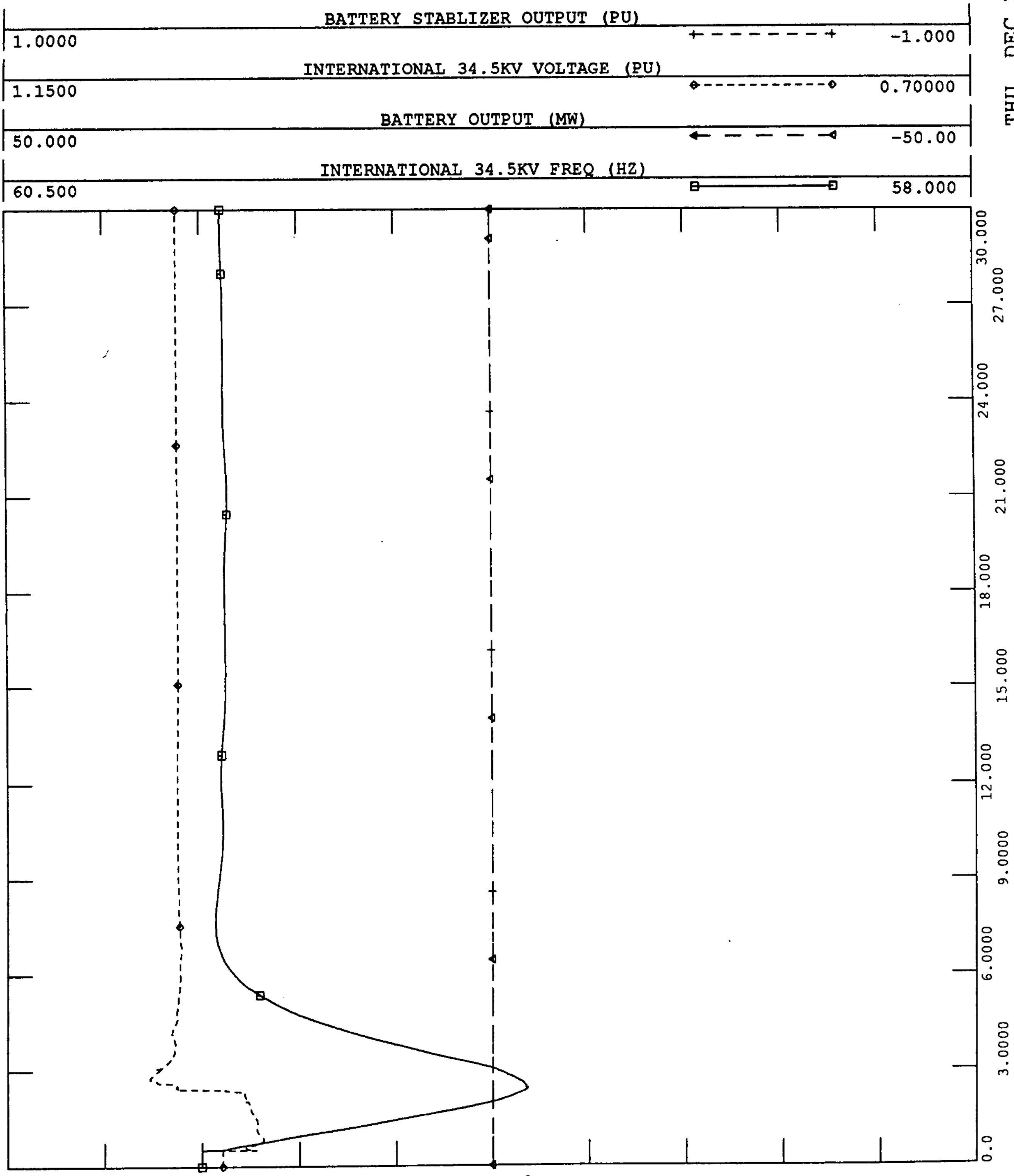
STABILITY ANALYSIS: SUMMER LOAD CASE

In this appendix, the simulations of the summer load case are presented. Under the summer load case, three scenarios were studied. In each scenario, the effects of various battery sizes, from 15 to 25 MW were examined. A simulation is also run without a battery. A disturbance consisting of a 50 MW loss of generation is used.

1989 SUMMER NORMAL LOAD. BELUGA 1 & 2 AT 5MW EACH.
NO BATTERY AT INTL 34.5KV.
TRIP UNIT # 6 & 7 AT 50 MW AT T=0.5 SECONDS.

FILE: B12U7-00.CHN

THU, DEC 26 1991 08:28
BATTERY RESPONSE

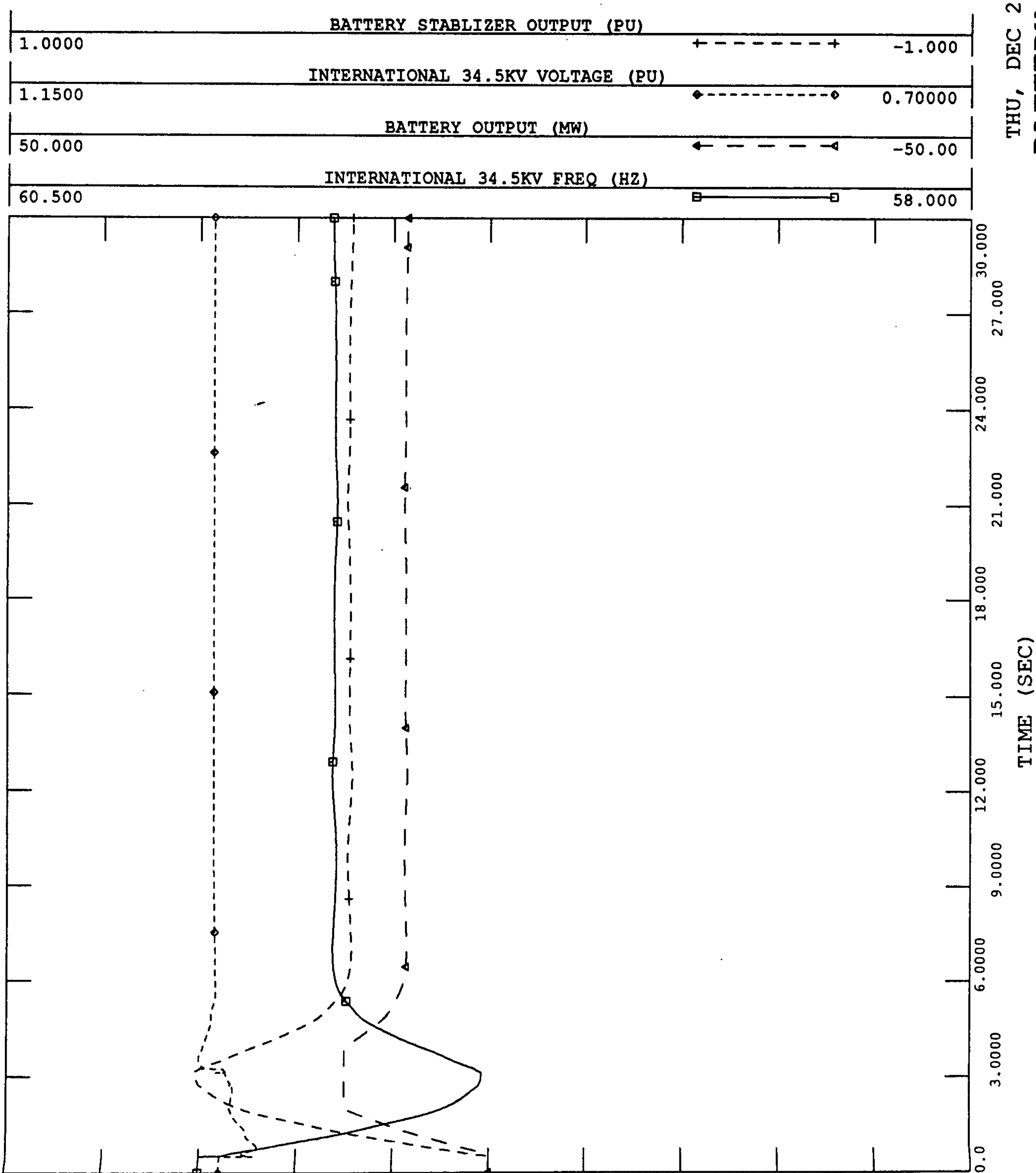


G-2

1989 SUMMER NORMAL LOAD. BELUGA 1 & 2 AT 5 MW EACH.
15 MVA BATTERY AT INTL 34.5KV, 0 MW OUTPUT. 1% DROOP.
TRIP UNIT # 6 & 7 AT 50 MW AT T=0.5 SECONDS.

FILE: B12U7-15.CHN

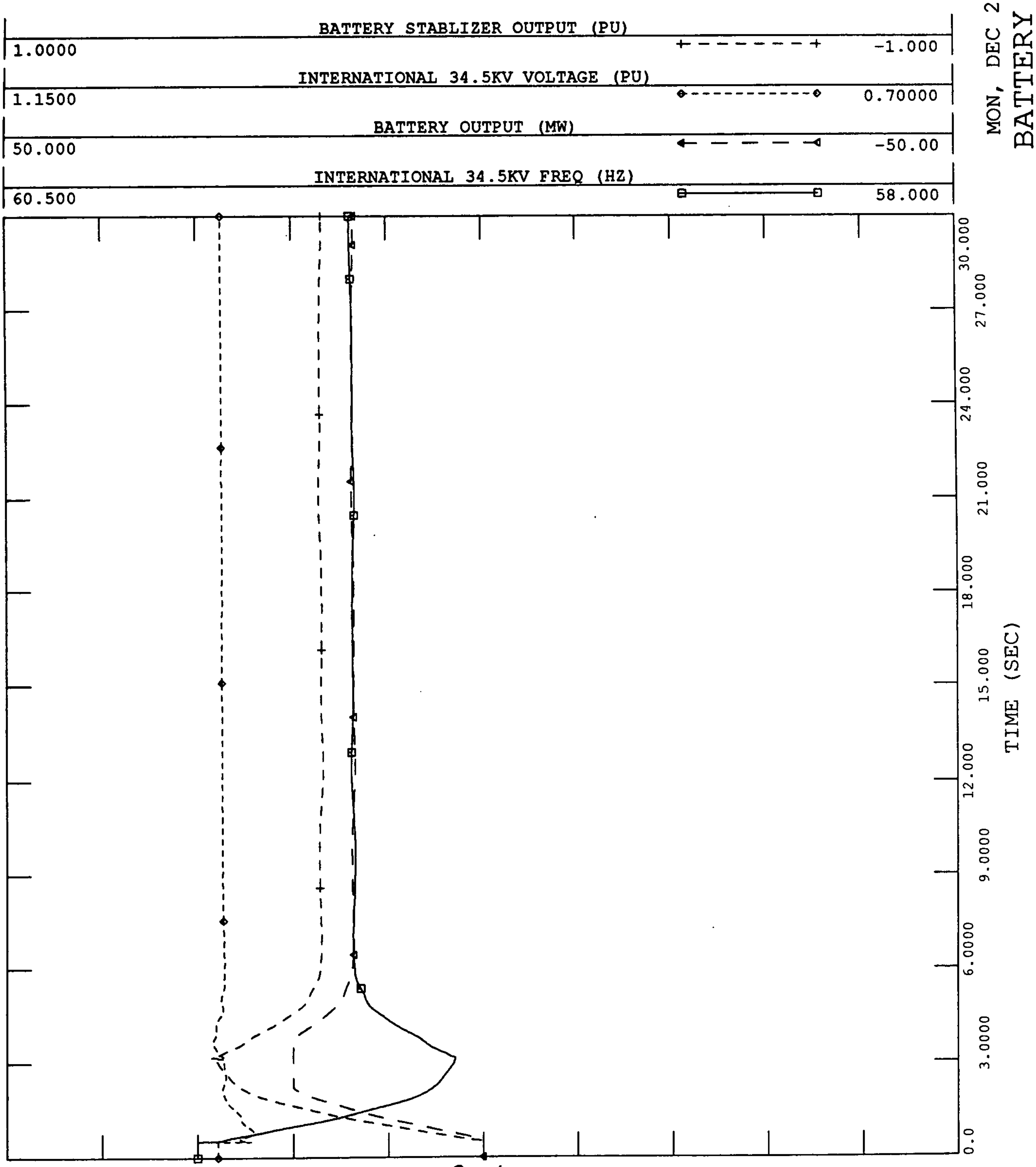
THU, DEC 26 1991 08:30
BATTERY RESPONSE



G-3

1989 SUMMER NORMAL LOAD. BELUGA 1 & 2 EACH AT 5MW.
20 MVA BATTERY AT INTL 34.5KV, 0 MW OUTPUT. 1% DROOP
TRIP UNIT #6 & #7 AT ~~95~~ 50MW AT T=0.5 SECONDS.
1% DROOP.

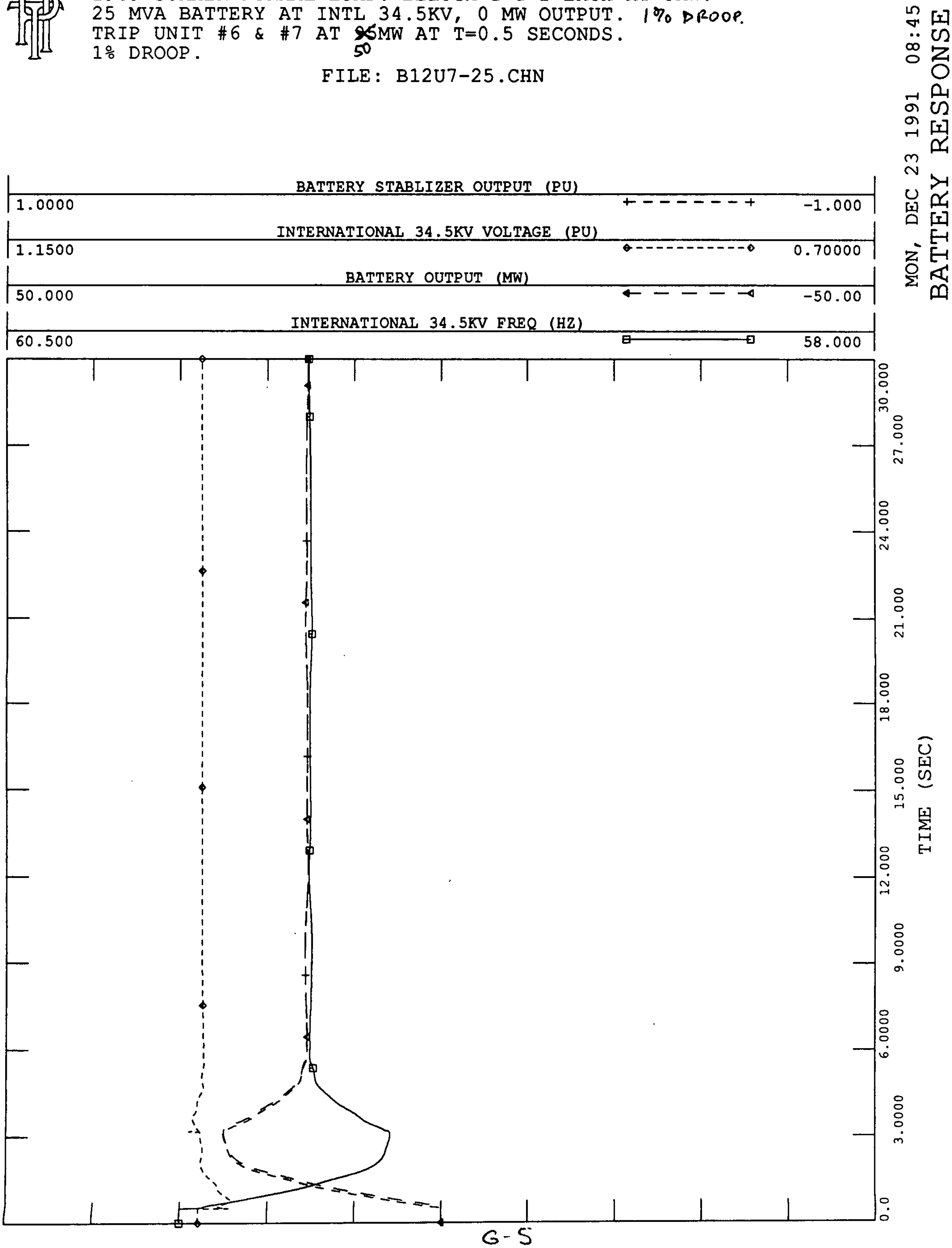
FILE: B12U7-20.CHN



G-4

1989 SUMMER NORMAL LOAD. BELUGA 1 & 2 EACH AT 5MW.
25 MVA BATTERY AT INTL 34.5KV, 0 MW OUTPUT. 1% DROOP.
TRIP UNIT #6 & #7 AT ~~95~~ 50MW AT T=0.5 SECONDS.
1% DROOP.

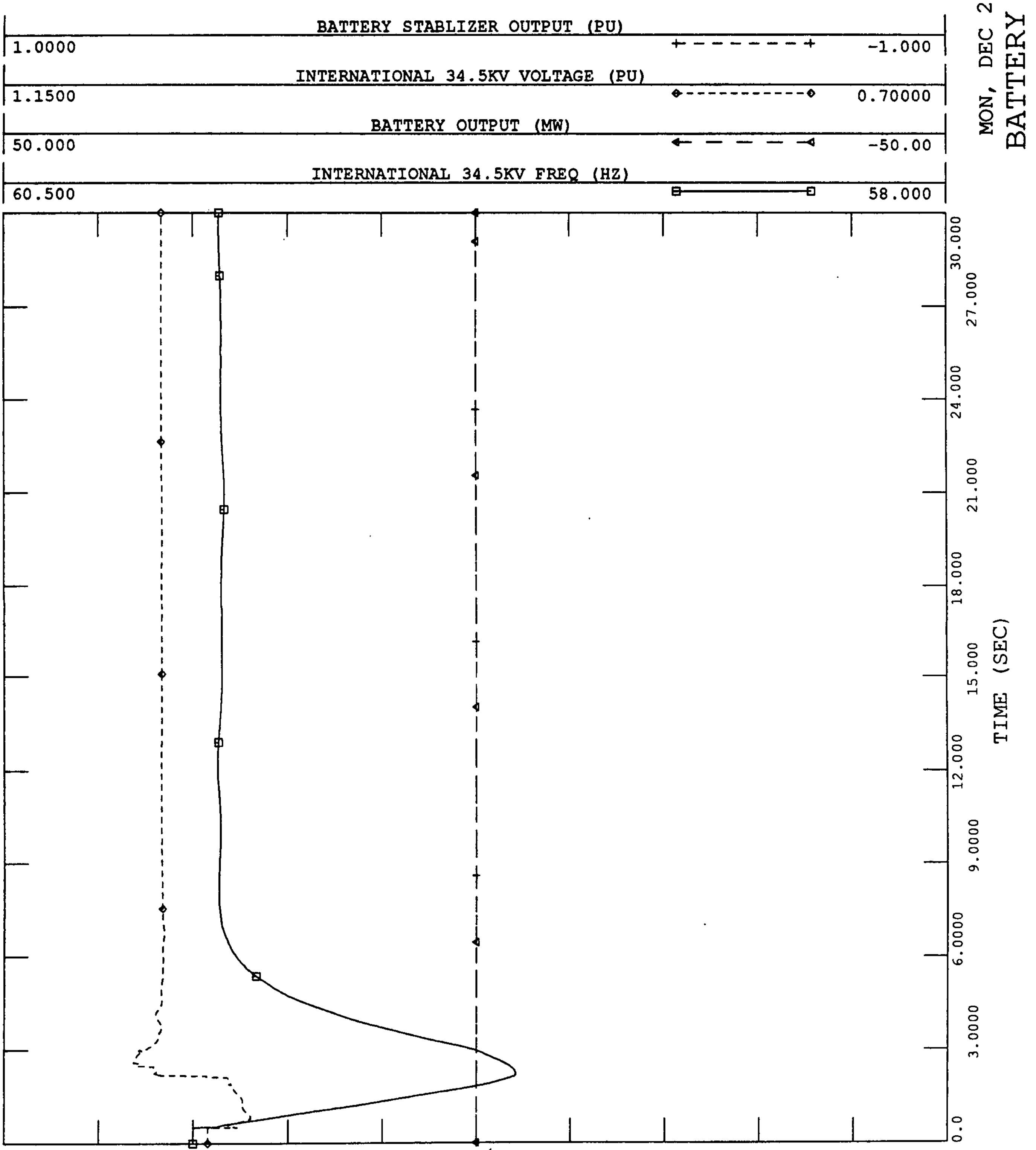
FILE: B12U7-25.CHN



1989 SUMMER NORMAL LOAD. BELUGA 1 AT 5MW.
NO BATTERY AT INTL 34.5KV.
TRIP UNIT #6 & #7 AT ~~95~~ 50MW AT T=0.5 SECONDS.
[redacted]

FILE: B10U7-00.CHN

MON, DEC 23 1991 08:48
BATTERY RESPONSE



1989 SUMMER NORMAL LOAD. BELUGA 1 AT 5MW.
15 MVA BATTERY AT INTL 34.5KV, 0 MW OUTPUT. 1% DROOP.
TRIP UNIT # 6 & 7 AT 50 MW AT T=0.5 SECONDS.

FILE: B10U7-15.CHN

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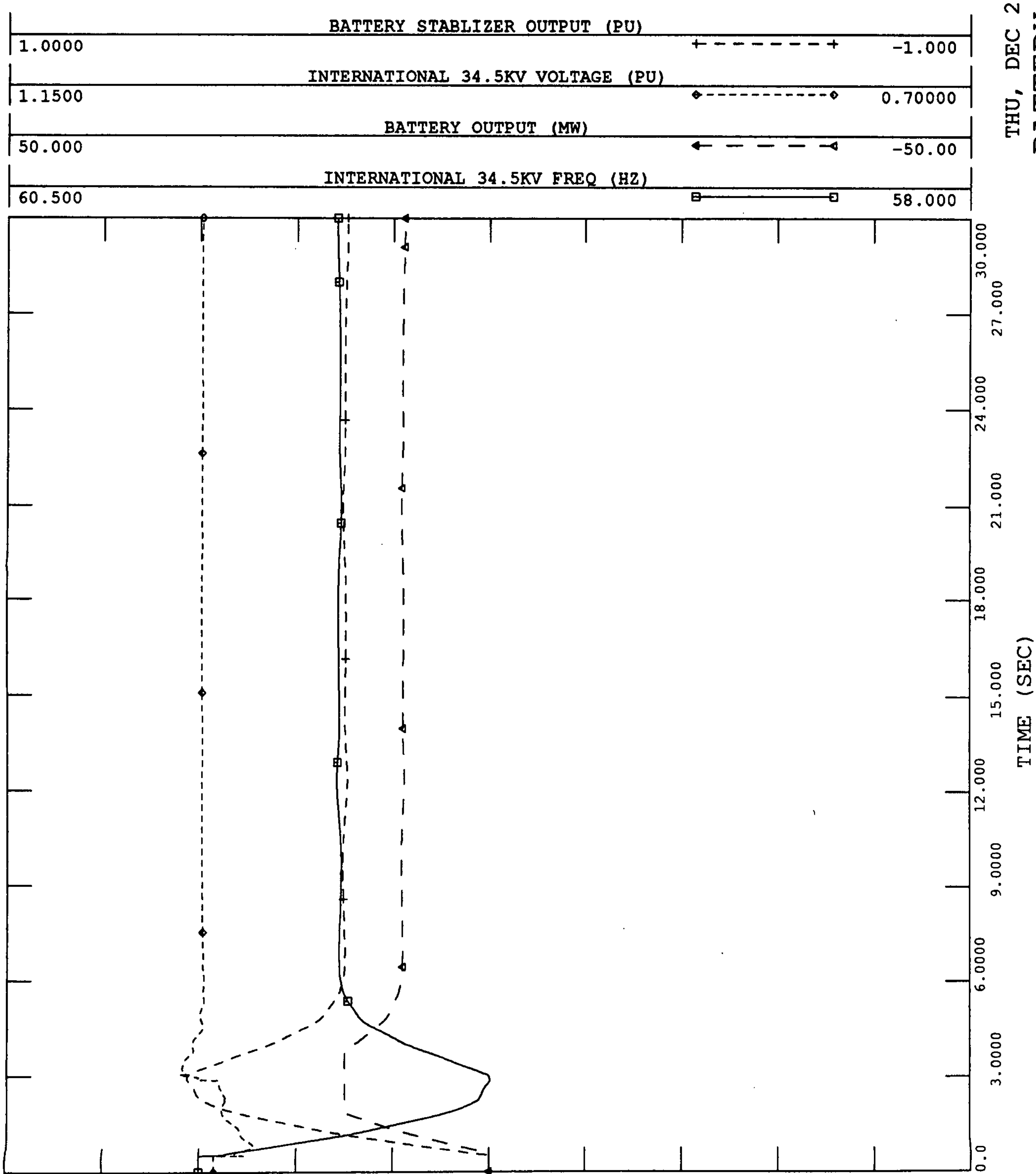
BATTERY RESPONSE



1989 SUMMER NORMAL LOAD. BELUGA 1 AT 5MW.
20 MVA BATTERY AT INTL 34.5KV, 0 MW OUTPUT.
TRIP UNIT #6 & #7 AT ~~96~~ 50 MW AT T=0.5 SECONDS.
1% DROOP.

FILE: B10U7-20.CHN

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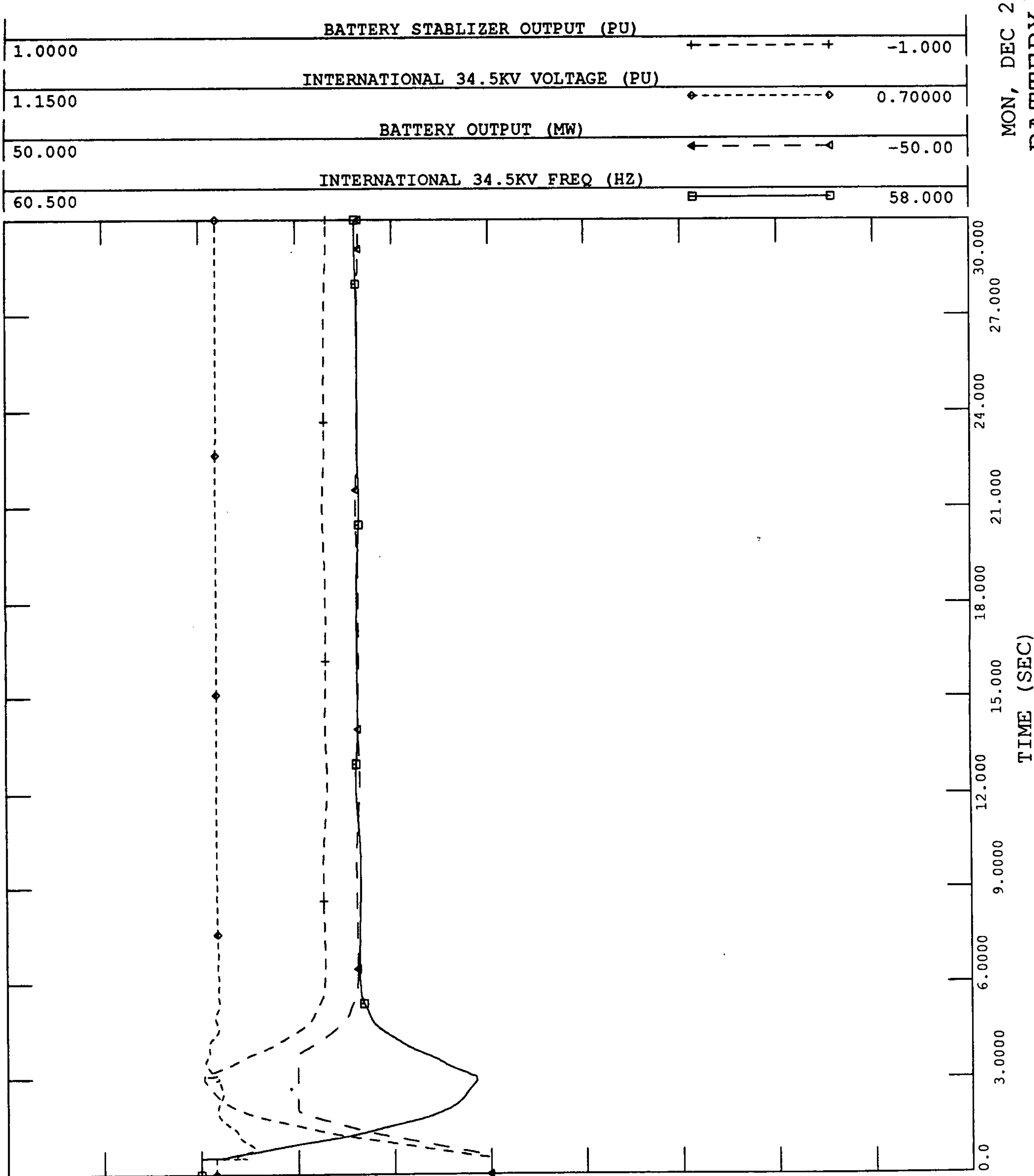
BATTERY RESPONSE

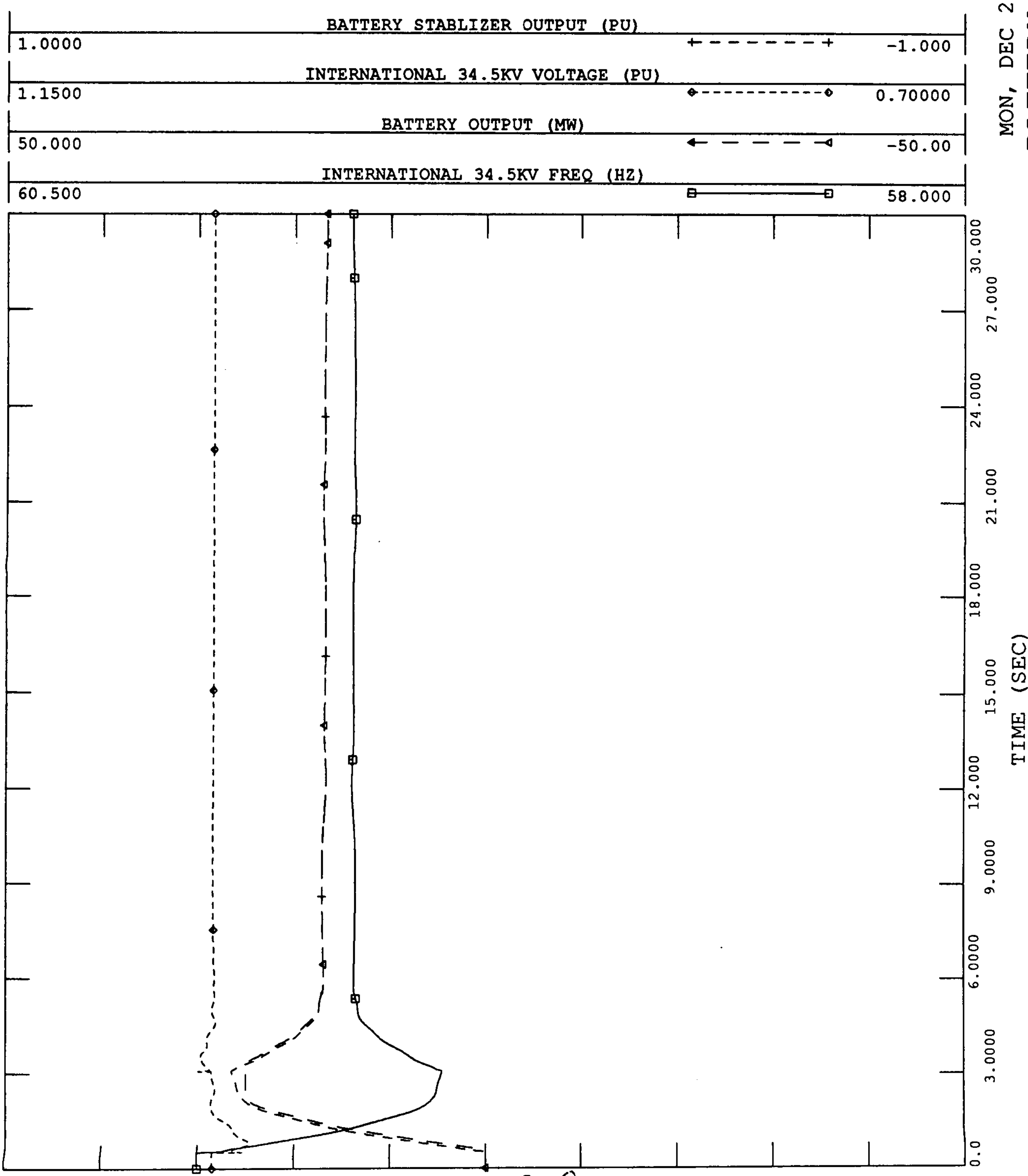


G-8

1989 SUMMER NORMAL LOAD. BELUGA 1 AT 5MW.
25 MVA BATTERY AT INTL 34.5KV, 0 MW OUTPUT.
TRIP UNIT #6 & #7 AT ~~95~~ 50MW AT T=0.5 SECONDS.
1% DROOP.

FILE: B10U7-25.CHN

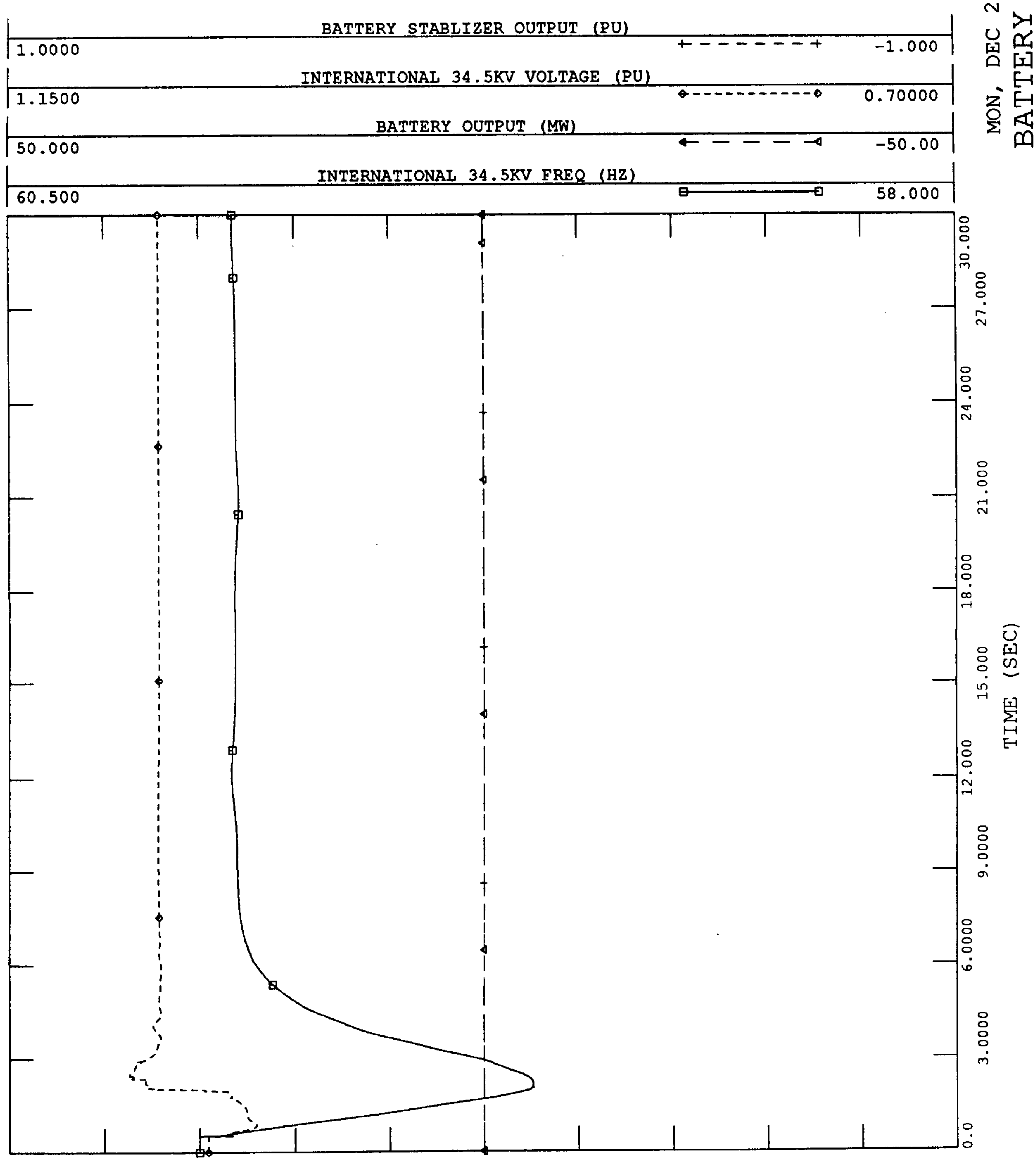
MON, DEC 23 1991 08:54
BATTERY RESPONSE



1989 SUMMER NORMAL LOAD. BRADLEY 1 & 2 EACH AT 15MW.
NO BATTERY AT INTL 34.5KV.
TRIP UNIT #6 & 7 AT ~~95~~ 50 MW AT T=0.5 SECONDS.

FILE: S89U7-00.CHN

MON, DEC 23 1991 08:19
BATTERY RESPONSE



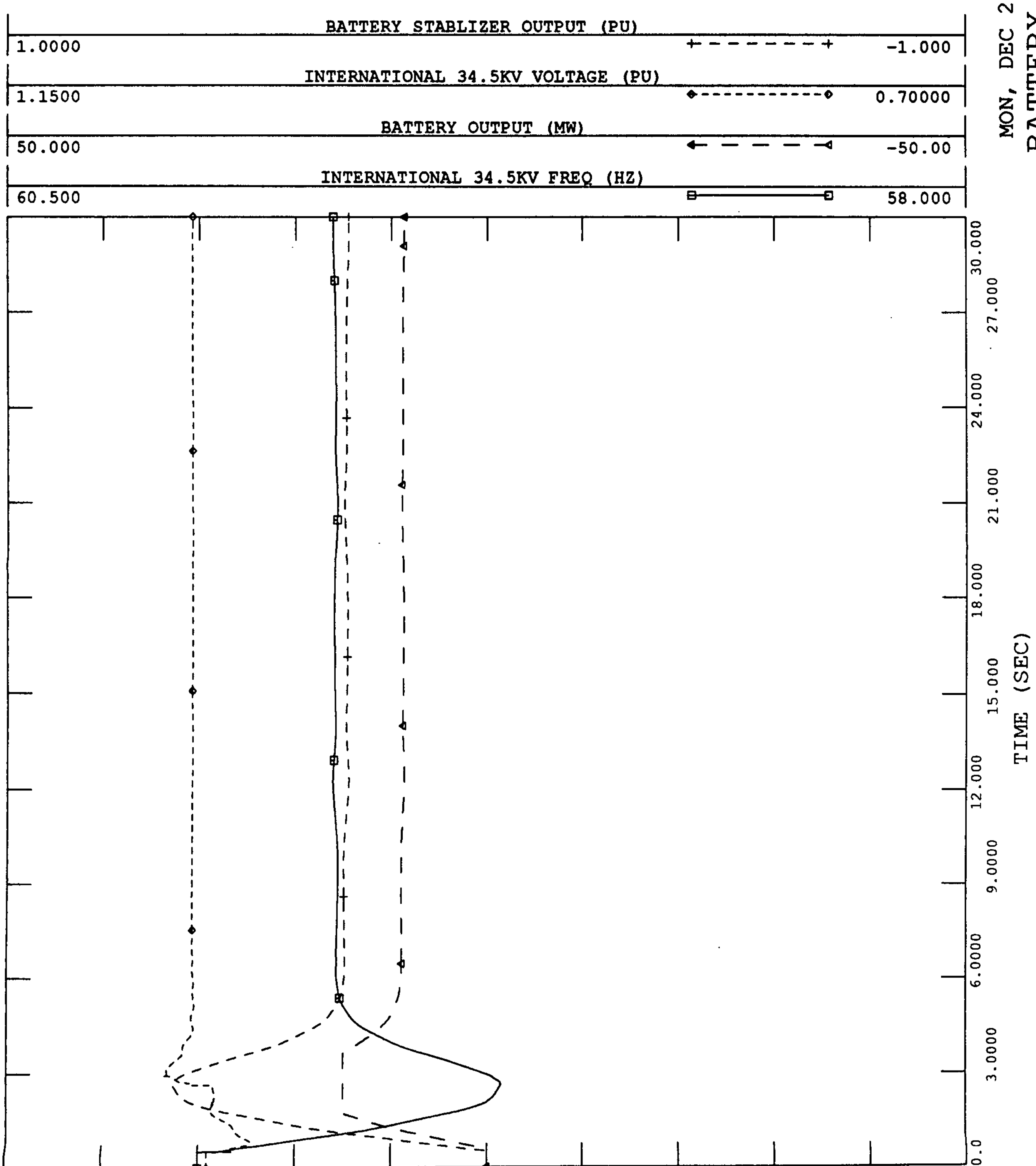
G-10

1989 SUMMER NORMAL LOAD. BRADLEY 1 & 2 EACH AT 15MW.
15 MVA BATTERY AT INTL 34.5KV, 0 MW OUTPUT.
TRIP UNIT #6 & #7 AT ~~95~~ 50 MW AT T=0.5 SECONDS.
1% DROOP.

FILE: S89U7-15.CHN

MON, DEC 23 1991 08:22

BATTERY RESPONSE



1989 SUMMER NORMAL LOAD. BRADLEY 1 & 2 EACH AT 15MW.
20 MVA BATTERY AT INTL 34.5KV, 0 MW OUTPUT.
TRIP UNIT #6 & #7 AT ~~96~~ 50 MW AT T=0.5 SECONDS.
1% DROOP.

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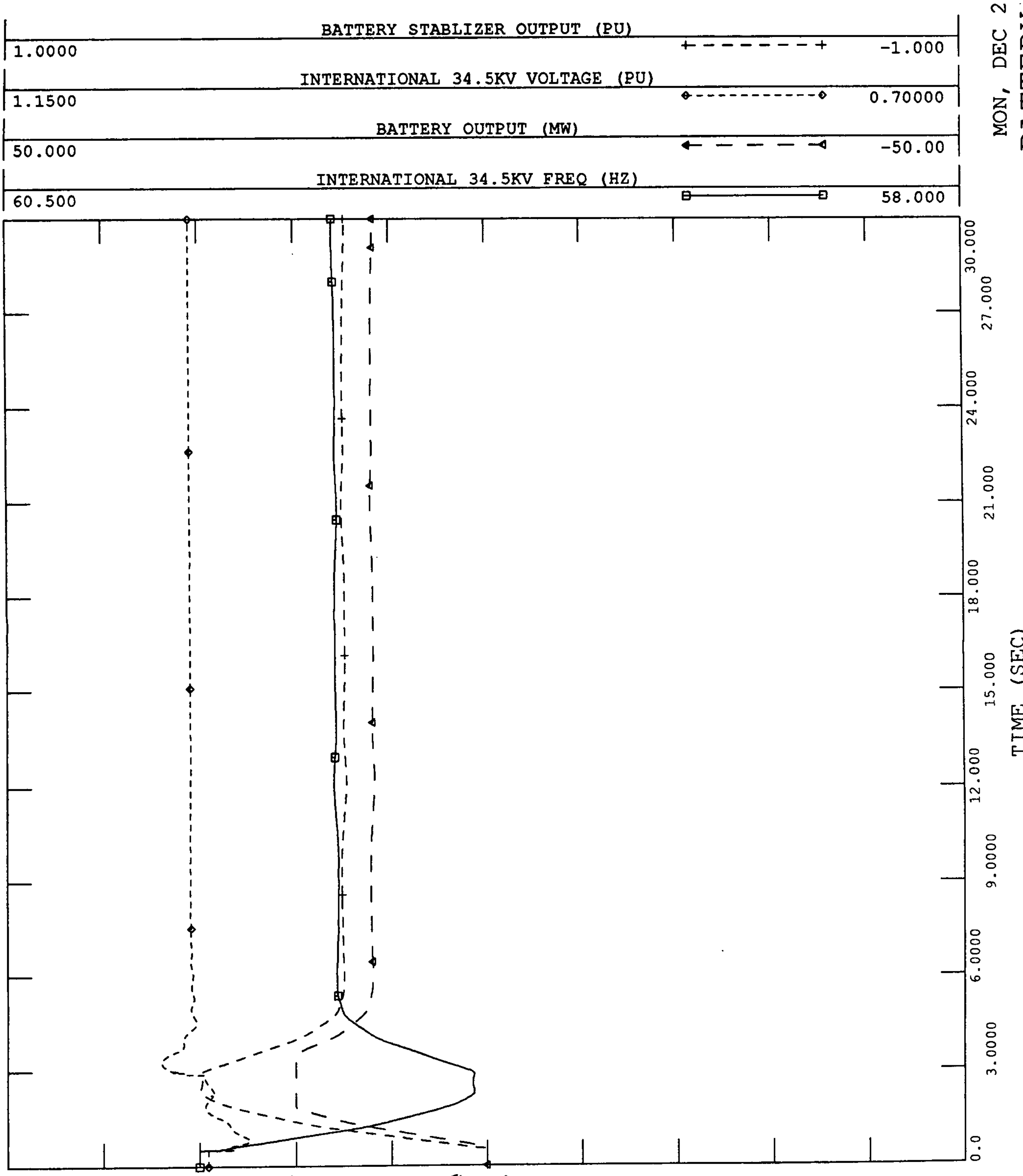
BATTERY RESPONSE

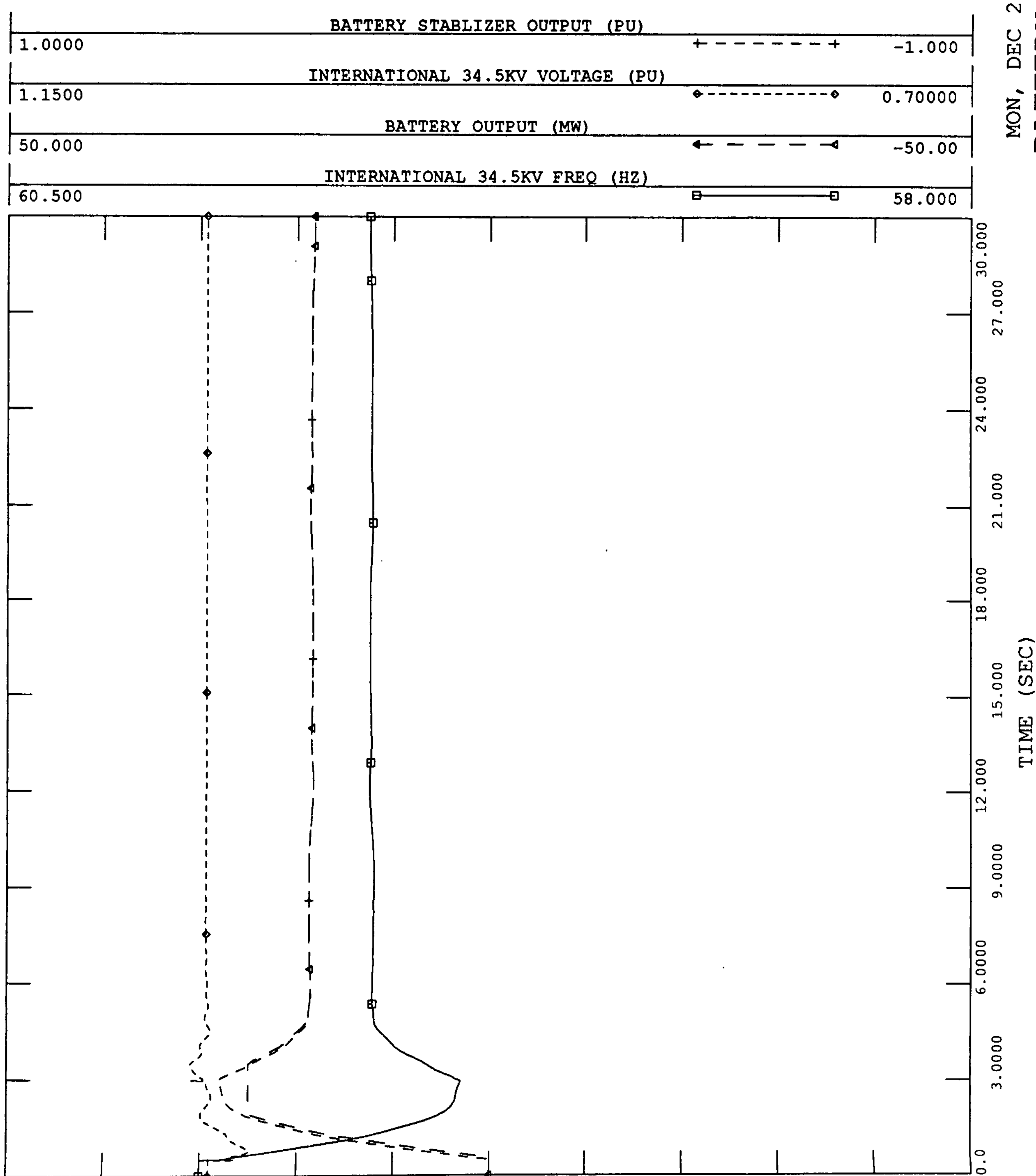


1989 SUMMER NORMAL LOAD. BRADLEY 1 & 2 EACH AT 15MW.
25 MVA BATTERY AT INTL 34.5KV, 0 MW OUTPUT.
TRIP UNIT #6 & #7 AT ~~95~~ 50 MW AT T=0.5 SECONDS.
1% DROOP.

FILE: S89U7-25.CHN

MON, DEC 23 1991 08:30

BATTERY RESPONSE



G-13

Appendix B

Potential Benefits of Battery Storage to San Diego Gas and Electric

POTENTIAL BENEFITS OF BATTERY STORAGE TO SAN DIEGO GAS AND ELECTRIC
—A Screening Study—

Prepared for:

Sandia National Laboratories
Department of Energy/Office of Energy Management

and

San Diego Gas and Electric

Prepared by:

Anders R. Gjerde
Stephen M. Haas
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DECISION FOCUS INCORPORATED

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and

H. W. Zaininger
H. C. Clark
Power Technologies, Inc.

January 1992

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EXECUTIVE SUMMARY

This report describes the results of a screening study to determine the benefits of adding megawatt-scale battery storage to the San Diego Gas and Electric (SDG&E) system. The report addresses generation, transmission, and distribution benefits of storage, with a primary focus on benefits that are typically difficult to quantify. The report also compares the potential benefits to the costs of adding battery storage.

BENEFITS OF ENERGY STORAGE

The addition of a storage unit to a utility system can provide a wide range of benefits that depend on the characteristics of the individual utility, the way in which the storage unit is operated, and the siting of the storage unit as well. Generation load-leveling has long been advocated as the primary reason for adding storage to a utility's generating mix. The most obvious benefit and the easiest to quantify, load-leveling results in the replacement of expensive peak power with cheaper power from base-load plants, increasing the capacity factor of the base-load plants during off-peak periods to displace the use of premium oil/gas fuels during on-peak periods. In the past several years, generation dynamic operating benefits (DOBs) have also been recognized as significant benefits of storage plants. The types of benefits include those accruing from the provision of spinning reserve, reduced minimum loading, and fast response rates. These benefits are overlooked in conventional methods. Another commonly recognized benefit from storage in general, and batteries in particular, is reduction in transmission and distribution (T&D) costs. T&D benefits are due in part to the siting flexibility and in part to the rapid response times for batteries. T&D benefits include deferral of T&D investment, reduced losses, and voltage regulation, as well as others.

SDG&E FINDINGS

Generation Benefits

Generation benefits were calculated for eight days during 1990-1991, one weekday and one weekend day for each season, using actual SDG&E data. The benefits were calculated for five gas-fired steam turbine units whose operation is most likely to be affected by the addition of batteries to the system. Two modes of battery operation were considered: daily charge/discharge with a three-hour battery, and provision of spinning reserve only with a one-hour battery.

Load-Leveling. Because the marginal units on the SDG&E system are typically gas-fired steam turbines for all hours (usually the Encina and South Bay units), the system marginal energy costs do not differ much between on-peak and off-peak hours. Coupled with the assumed battery efficiency of around 80 percent, this means that no load-leveling savings could be achieved on the SDG&E system.

Dynamic Operating. For each of the eight days the potential reduction in load following, minimum loading, startup, and spinning reserve costs was calculated for each of the five units. The most cost-effective unit for decommitment was identified on each day. For the 1990-1991 period, the savings was about $23-26 per kilowatt per year of battery capacity; the biggest component of the savings is from reductions in load-following costs. That is, each kilowatt of battery capacity would reduce annual system operating costs 23 to 26 dollars. Accounting for inflation and increases in natural gas prices, this is equivalent to an annual savings of about $50, levelized in current dollars, per kilowatt per year. The savings are likely to increase in the future as load growth forces increasing utilization of less economic units.

Environmental. Storage in general, and batteries in particular, have the potential to shift the type and location of emissions of NO_x, SO_x, and CO_2; NO_x is of greatest concern in Southern California. Even if providing only spinning reserve, batteries have the potential to reduce NO_x emissions by allowing the system to be operated more efficiently. The addition of batteries to the system might also make it unnecessary to retrofit expensive pollution controls to an existing gas-fired unit, if that unit's operation would be sharply reduced as a result of adding batteries.

Transmission and Distribution Benefits

This project identified the potential role battery storage could play in providing equal or better performance than other transmission and distribution (T&D) options, such as adding new T&D facilities and equipment. Current SDG&E transmission and distribution facility expansion study results and transmission and distribution system design practices were reviewed with SDG&E personnel to identify anticipated and potentially needed transmission additions.

The findings of this initial study indicate that strategically installing battery storage on the SDG&E system may result in large T&D system benefits—up to $1200/kW. The actual magnitude of the site specific T&D benefits and corresponding battery storage requirements should be determined on a case-by-case basis from more detailed analysis. Further analysis should include the development of load profiles for substations that are candidate battery sites so that the number of hours of storage required for equipment deferral can be determined.

COST/BENEFIT ANALYSIS

Table S-1 summarizes the findings. Summing the capacity, generation, environmental, and T&D benefits yields levelized current-dollar savings of $100 to $370/kW-year, compared to a levelized current-dollar cost of $60 to $130/kW-year.[1] These values suggest that batteries would be a cost-effective addition to the SDG&E system.

1. There are no commonly accepted estimates for battery storage system costs. The cost estimates used here are from EPRI's Technical Assessment Guide (TAG, 1989). The total cost is $703/kW for a 3-hour battery, including land cost. Reducing the storage component in the TAG cost estimates for a 3-hour battery by two thirds yields an estimated cost of $350/kW for a 1-hour battery. With a levelized fixed charge rate of 16 percent, this is equivalent to $60/kW-year for a 1-hour battery and $130/kW-year for a 3-hour battery.

Table S-1
BENEFITS SUMMARY FOR SDG&E SYSTEM

Category	Annual Benefit ($/kW-year)
Capacity	40-75
Generation	50-75
T&D	10-200
Environmental	1-20*
TOTAL	100-370

*For charging with on-system units.

Some benefits may be mutually exclusive. The interactions between the various benefits, i.e., whether they are additive or mutually exclusive, depends on storage size, location, system load shapes, load shapes at individual substations and on individual transmission and distribution lines, how the system (including the battery) is operated, and on any equipment deferred as a result of adding batteries.

RECOMMENDATIONS

Based on the results of this screening-level study, it is recommended that SDG&E seriously consider the addition of battery storage to its system. A detailed study to verify the findings of this initial screening study and to calculate the benefits more precisely is recommended. Such a study should include the following aspects:

1. More detailed calculation of generation dynamic operating costs and benefits should be carried out, including examination of multiple weeks of system operation during the course of the year and consideration of how system operation, and especially the operation of marginal units, is likely to change in the future.

2. Detailed T&D expansion studies should be carried out, with and without batteries. Potential sites for installing batteries should be identified. Interactions among the various benefits should be considered to ensure that batteries are not being justified on the basis of benefits that may be mutually exclusive.

3. Comparative evaluation of the economics of battery storage with other capacity additions under consideration by SDG&E should be carried out.

Such detailed study would also allow a better assessment of the "optimum" battery size and the best time for adding the battery plant to the SDG&E system.

1

INTRODUCTION

This report describes the results of a screening study to determine the benefits of adding megawatt-scale battery storage to the San Diego Gas and Electric (SDG&E) system. The report addresses generation, transmission, and distribution benefits of battery energy storage, with a primary focus on benefits that are typically difficult to quantify. The potential benefits are compared to the costs of adding battery storage to determine the cost-effectiveness of adding battery energy storage to the SDG&E system.

BENEFITS OF ENERGY STORAGE

The addition of battery energy storage to a utility system can provide a wide range of benefits that depend on the characteristics of the individual utility, the manner in which the battery storage unit is operated, and its siting within the utility network as well. Generation load-leveling has long been advocated as the primary reason for adding storage to a utility's generating mix. The most obvious benefit and the easiest to quantify, load-leveling results in the replacement of expensive peak power with cheaper power from base-load plants, increasing the capacity factor of the base-load plants during off-peak periods to displace the use of premium oil/gas fuels during on-peak periods.

In the past several years, generation dynamic operating benefits (DOBs) have also been recognized as significant benefits of battery energy storage plants. The types of benefits include those accruing from the provision of spinning reserve, reduced minimum loading, and fast response rates. An EPRI report[1] provides compelling evidence on the importance of dynamic operating considerations. The three major conclusions of the EPRI report are as follows:

- A large portion of the operating costs of cycling power plants results from fluctuating electric loads. These costs are called *dynamic operating costs*.

- Technologies that offer operating flexibility at minimal costs (e.g., energy storage power plants) provide power systems with significant operating cost savings. These savings are called *dynamic operating benefits*.

- A large fraction (up to two-thirds) of the savings provided by technologies with significant operating flexibility is overlooked in conventional methods.

---

1. *Dynamic Operating Benefits of Energy Storage*, EPRI AP-4875.

Another commonly recognized benefit from storage in general, and batteries in particular, is reduction in transmission and distribution (T&D) costs. T&D benefits are due in part to the siting flexibility and in part to the rapid response times for batteries. T&D benefits include deferral of T&D investment, reduced losses, and voltage regulation, as well as others.[2]

Another category of benefits is what might be termed strategic benefits, those that relate primarily to the changing environment in which utilities operate. This includes reduction in environmental emissions, greater ability to buy power from other utilities and from non-utility generators and to sell power to other utilities, and greater flexibility in general.

This study quantifies the benefits of battery storage in the first two categories—generation and T&D—for the SDG&E system.[3] It then compares these benefits to the costs of adding lead-acid battery storage.

LEAD-ACID BATTERY TECHNOLOGY[4]

The major elements of a lead-acid battery energy storage plant are the battery, the converter, and the balance of the plant. During charging, alternating current electricity is converted to direct current electricity by the converter and stored electrochemically by the battery. During discharge, direct current electricity is drawn from the battery and converted to alternating current electricity for use on the utility grid. Figure 1-1 is a schematic of a battery energy storage system.

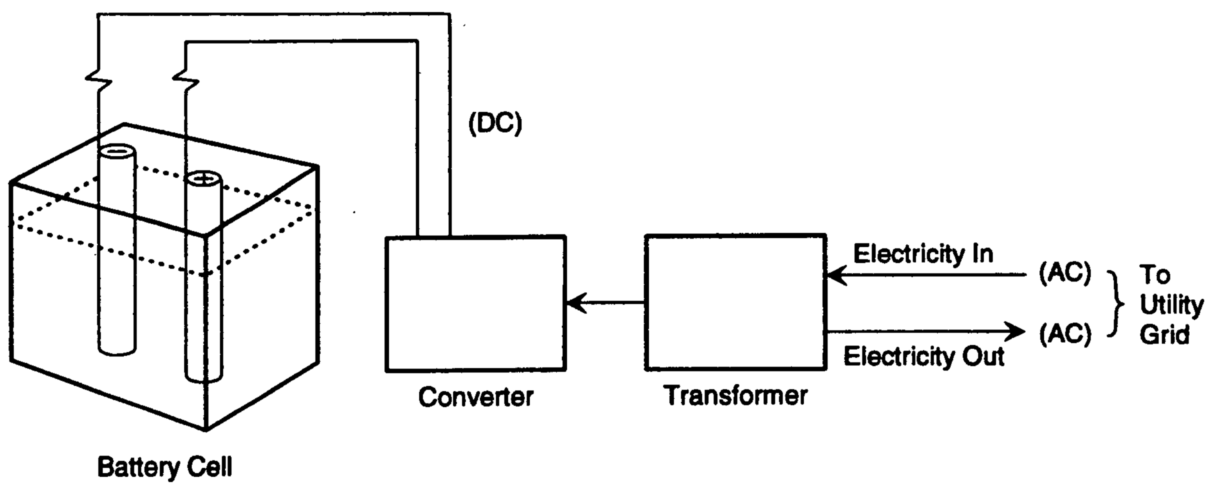

Figure 1-1. Battery Energy Storage System

2. *Potential Economic Benefits of Battery Storage to Electrical Transmission and Distribution Systems,* EPRI GS-6687.

3. A back-of-the envelope assessment of environmental benefits is also included.

4. Research is under way on a number of advanced battery systems, including sodium sulfur, zinc bromine, and others. In this report, however, we focus on and use costs for the one technology that is commercially available now: lead-acid batteries.

Utility battery storage systems consist of commercially available lead-acid cells similar to those used in submarines or large telephone switching installations. A typical cell size is 5 to 10 kWh. Many cells are combined in a battery unit, with typical storage times of 1 to 5 hours and power capacities of 2 to 100 megawatts. For example, the 4-hour capacity lead-acid battery storage plant at Southern California Edison Company's Chino substation has a capacity of 10 MW; the battery consists of 8,256 cells, each measuring approximately 16 in. (41 cm) long, 14.5 in. (37 cm) wide, and 25 in. (65 cm) high, and weighing about 585 lb. (266 kg). The cells are mounted on steel frames in groups of 6 to form 12-V modules. The battery is connected to the SCE system at 13.8 kV.

The AC-DC converter consists of electronic equipment similar to that used in large uninterruptible power supply (UPS) systems, and in wind, photovoltaic, and fuel cell power generation systems. The balance of the plant consists of the structural, mechanical, electrical, control, and safety subsystems required to perform system integration and interface of the battery to the utility system.

Battery energy storage plants are truly modular and can be installed quickly, enabling them to match load growth much more easily and accurately than larger, custom-built, site-specific plants. Construction time for a lead-acid battery plant is less than one year. Batteries are compact, quiet and non-polluting, so they can be sited near population centers. They can operate efficiently over a wide range of loads, and are actually more efficient at part load than at full load. They can also respond to load changes in just 20 milliseconds.

Table 1-1 provides cost and performance data for battery storage sizes of 3 and 5 hours, installed at a 20 MW plant. These data are from the EPRI Technical Assessment Guide™.

Table 1-1
LEAD-ACID BATTERY COST AND PERFORMANCE DATA

	Three Hour	Five Hour
Plant Capital Cost, Dec. 1988 $/kW		
Power charging/discharging	125	125
Storage	510	727
Startup, inventory, land	16	21
Total capital requirement	651	873
Operation and Maintenance Costs, Dec. 1988 $		
Fixed, $/kW-yr	0.6	1.4
Incremental, mills/kWh	8.6	6.5
Energy Requirements (kWh Output/kWh Input)		
Full load	0.73	0.76
25% load	0.78	0.79
Average annual	0.74	0.76
Plant Construction Time, Years	1	1
Unit Life, Years	30	30

SDG&E SITUATION

SDG&E's generation mix consists of nuclear, gas-fired units, and purchased power. From the perspective of adding battery storage to the system, the important point is that both now and perhaps for the rest of the 1990s, the marginal units are almost always, both on-peak and off-peak, gas-fired units. These are the units whose operation would be affected by the additions of batteries.[5] This means that, for on-system units, there is relatively little difference in incremental energy costs between peak and off-peak periods, so that from a load-leveling perspective, there is not much benefit from adding batteries. Other types of benefits, such as T&D and dynamic operating, will be required if the addition of batteries is to be economically justified.

Based on SDG&E's current biennial resource plan update (BRPU), which is filed every two years with the state Public Utilities Commission (PUC), the preferred plan resource additions for SDG&E are shown in Table 1-2.

Table 1-2
PREFERRED PLAN RESOURCE ADDITIONS

Year	Projected Generation Additions
1997	Repower South Bay Unit Number 3: 455 added MW. Additional Purchased Power: 372 added MW. Geothermal: 100 added MW.
1999	Repower Encina unit #1: 273 added MW.
2001	Repower one Encina unit or construct combined cycle plant on SDG&E site in Blythe
1991-2000	Non-utility generation: 800 MW
Year	**Projected DSM Savings**
1995	240 MW
2000	360 MW

OVERVIEW OF THIS REPORT

Section 2 quantifies the generation benefits of batteries on the SDG&E system. Sections 3 and 4 do the same for transmission and distribution, respectively. Section 5 compares these benefits to the cost of installing batteries. Section 6 summarizes the results and recommends further steps.

5. While SDG&E does have combustion turbines, currently they are operated only infrequently.

2

POTENTIAL GENERATION BENEFITS

This section estimates the magnitude of three kinds of generation benefits—load-leveling benefits, dynamic operating benefits, and environmental benefits—of adding battery storage to the SDG&E system. The section discusses the logic behind the calculations, describes the approach taken for the SDG&E analysis, and presents the results.

CALCULATING GENERATION BENEFITS OF ENERGY STORAGE

Load-Leveling Benefits

Energy storage makes it possible to generate electricity during off-peak hours and use it during peaking-hours, commonly referred to as load-leveling. Typically, system lambda (the marginal cost of energy) is lower during off-peak hours than during on-peak hours; the load-leveling savings is the difference between the lambda during peaking hours when the storage would be discharged and the lambda for the off-peak hours, when the storage would be charged, adjusted for the efficiency loss from the battery.

$$\underset{(\$/\text{MWh})}{\text{Load Leveling Benefits}} = \underset{(\$/\text{MWh})}{\lambda_{\text{on-peak}}} - \underset{(\$/\text{MWh})}{\lambda_{\text{off-peak}}}/\text{storage efficiency}$$

If this number is positive, then there are load-leveling savings. This will be true if the battery efficiency exceeds the ratio of off-peak lambda to on-peak lambda.

Dynamic Operating Benefits

Dynamic operating costs (DOCs) are the portion of total operating costs of an electric power system required to meet dynamic operating requirements. Technologies that offer operating flexibility at minimal costs, such as energy storage plants, provide power systems with significant operating cost savings. These savings are called dynamic operating benefits (DOBs). Potential DOBs are measured as reductions in dynamic operating costs (DOCs). DOCs include:

- Startup costs, the costs of shutting down and starting up power plants.
- Load Following costs, increased fuel costs due to operations in load following mode.

- Minimum Load costs, costs due to foregone economic generation because of minimum load constraints.

- Ramping costs, the costs due to foregone economic generation because of ramping constraints.

- Frequency Regulation costs, costs of foregone economic generation due to externally constraining the loading ranges of some units to provide frequency regulation capabilities.

This study estimated the benefits associated with reducing the first three types of dynamic operating costs: startup costs, load following costs, and minimum load costs, all of which have a solid technical foundation based on common utility operations. Other categories of DOBs are likely to be smaller but can only add to the DOBs quantified in this study.

Startup Cost Benefits. The cost of starting a steam unit that has been shut down completely is typically several thousand dollars. Compared to the total daily operating cost of such a unit, typically tens of thousands of dollars per day, this is not insignificant. By modifying unit commitment, the addition of battery storage can make it possible to avoid this startup cost for one or more units.

Load Following Benefits. Load fluctuation requires that some generation be able to meet changes in, or follow, the load. As a result of this requirement, the units used for load following will most of the time be loaded at levels other than their most efficient loadings, at points where their average fuel costs are higher than at their most efficient loadings and higher than system marginal cost. Load following benefits occur when a unit operating in load following mode is decommitted. The benefits or savings are equal to the difference in average energy cost of the unit and the system marginal energy cost.

Load following costs of a unit are the costs which could have been avoided were the system able to decommit the unit and replace its energy at the system marginal energy cost. These are calculated for hours where the unit is operated at part load (not on minimum load):

$$\begin{array}{c}\textit{Load Following}\\ \textit{Costs of a Unit}\\ (\$/hr)\end{array} = \left(\begin{array}{c}\textit{Average Energy}\\ \textit{Cost of the Unit}\\ (\$/MWh)\end{array} - \begin{array}{c}\textit{System Marginal}\\ \textit{Energy Cost}\\ (\$/MWh)\end{array} \right) * \begin{array}{c}\textit{Loading of Unit}\\ (MWh/hr)\end{array}$$

The daily load following costs are the sum of the hourly load following costs (for the hours in load following mode).

Minimum Load Benefits. Thermal units have minimum loading constraints. When they are committed, they must be operated at or above this minimum load. Operation at minimum loading generally results in the least efficient generation. Units are normally operated at their minimum load only because the constraint prohibits even lower loading. Minimum loading benefits occur when a unit operating at its minimum load is decommitted. The benefits or savings are equal to the difference in average energy cost of the unit and the system marginal energy cost.

Minimum loading costs of a unit are the costs which could have been avoided were the system able to decommit the unit and replace its energy at the system marginal energy cost, calculated for hours where the unit is on minimum load:

$$\begin{array}{c}\textit{Minimum Load}\\ \textit{Costs of a Unit}\\ (\$/hr)\end{array} = \left(\begin{array}{c}\textit{Average Energy}\\ \textit{Cost of the Unit}\\ (\$/MWh)\end{array} - \begin{array}{c}\textit{System Marginal}\\ \textit{Energy Cost}\\ (\$/MWh)\end{array}\right) * \begin{array}{c}\textit{Minimum}\\ \textit{Loading of Unit}\\ (MWh/hr)\end{array}$$

The daily minimum load costs are the sum of the hourly minimum load costs (for the hours at minimum load).

Figures 2-1 and 2-2 illustrate how minimum load and load following costs are calculated and how significant they can be. Although the figures are for a hypothetical unit in a hypothetical system, they are typical of actual units. The unit operates at its minimum load for hours 0-4 and 20-24, at its maximum load for hours 8-16, and in load-following mode during the other 8 hours. The daily load following cost of the unit is the dark shaded area in Figure 2-2; the light shaded area is the unit daily minimum load cost. The difference between unit average cost, which is the cost actually incurred, and system marginal cost, the cost that would be incurred if this unit could be shut down, is substantial.

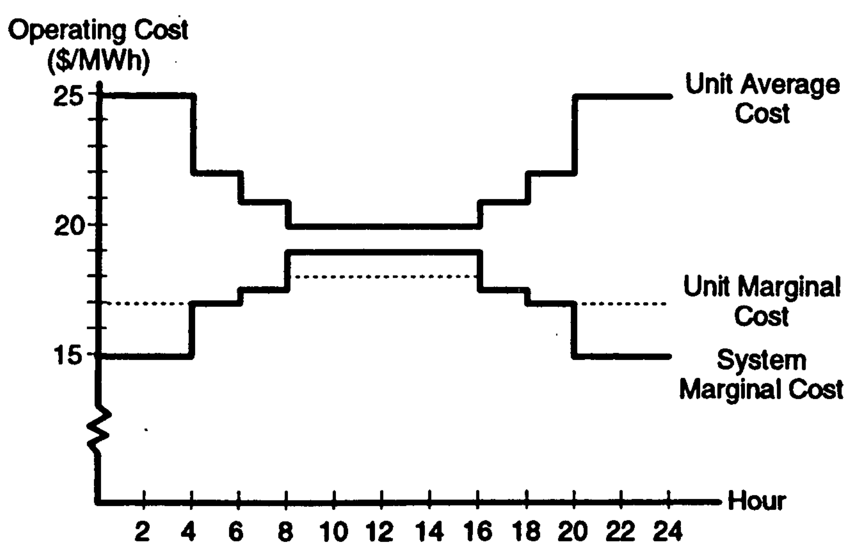

Figure 2-1. System and Unit Costs

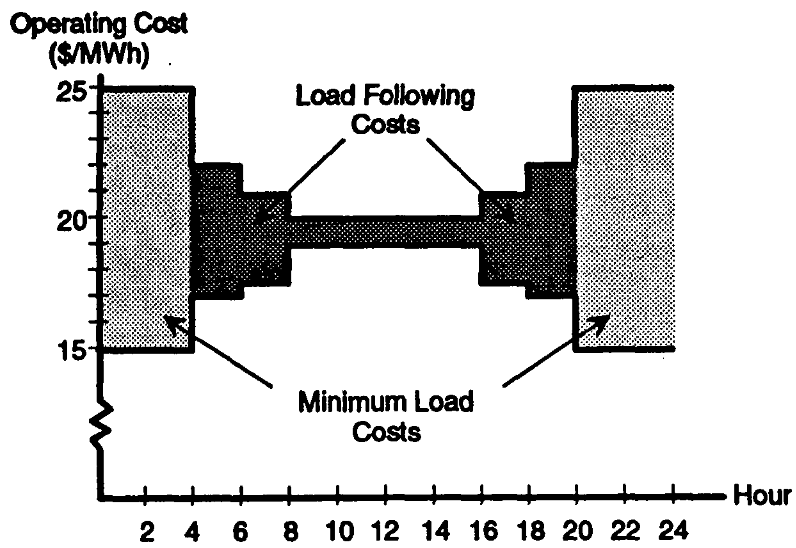

Figure 2-2. Load Following Costs and Minimum Load Costs

CAPTURING GENERATION BENEFITS OF ENERGY STORAGE

There are two primary modes in which storage can be operated:

- On a regular charge/discharge basis
- To provide spinning reserve only

Both modes are discussed below.

Charge/Discharge Application

Operated in this mode, storage provides not only load-leveling but also the reduction in dynamic operating costs made possible by decommitting a unit and operating remaining units at more efficient levels. The storage would most likely be operated on a daily cycle, with charging at night and discharging during the daily peak. In order to maximize benefits per kilowatt of battery capacity, it is necessary to install both enough power capacity (MW) and storage capacity (MWh or hours of storage) to permit decommitting one or more units.

To illustrate the importance of including dynamic operating costs in calculating generation benefits, consider a hypothetical system with two time periods per day, a peak period of 8 hours, and an off-peak period of 16 hours. The system marginal energy costs are $18/MWh during the peak period and $17/MWh during the off-peak period. Figure 2-3 illustrates these marginal energy costs and Table 2-1 illustrates the operating characteristics of one generation unit (called Unit A). Unit A operates at minimum load (50 MW) during the off-peak period and at 100 MW during the peak period. Figure 2-4 illustrates the power output of Unit A.

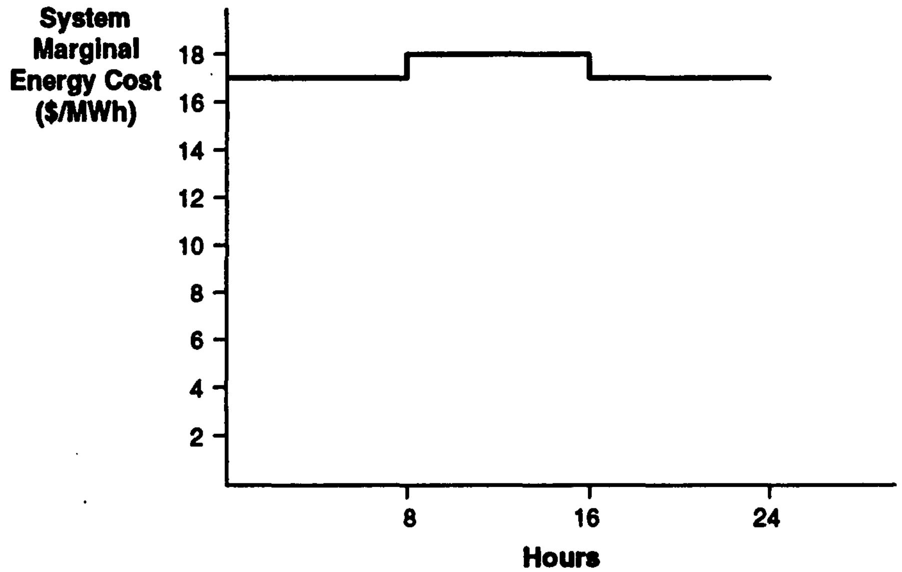

Figure 2-3. System Marginal Energy Costs

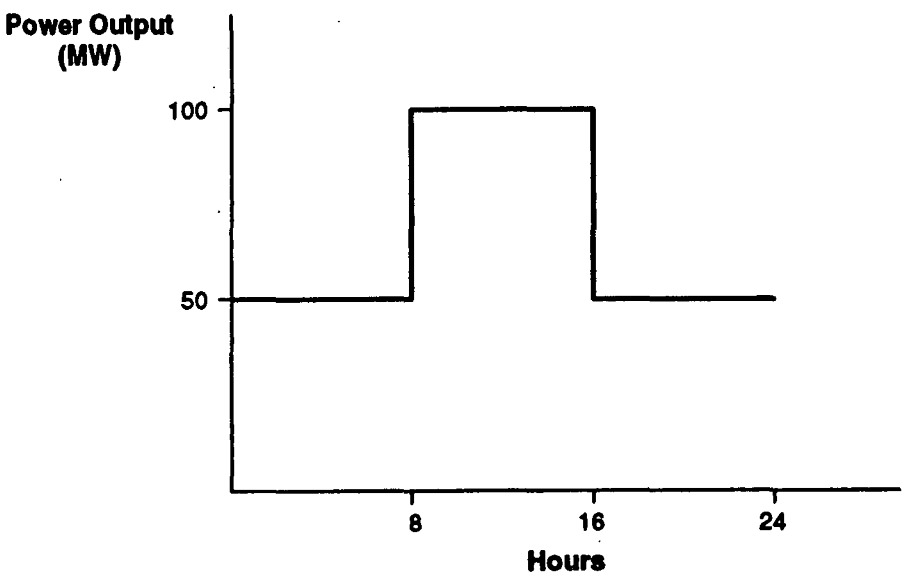

Figure 2-4. Power Output of Unit A

Table 2-1
OPERATING CHARACTERISTICS OF GENERATION UNIT A

Power Output (MW)	Average ($/MWh)	Marginal ($/MWh)
50	25.0	
100	21.0	17.0
150	20.0	18.0

Would a storage unit with a 77 percent cycle efficiency provide this system with any operating savings? Using the conventional approach (that does not include dynamic operating considerations), the benefit to cost ratio of storage operatings is calculated as follows:

$$B/C = 0.77 \times \frac{\textit{Marginal Energy Cost During the Peak Period}}{\textit{Marginal Energy Cost During the Off-Peak Period}}$$

$$= 0.77 \ \frac{18.0}{17.0}$$

$$= 0.815 < 1.0$$

Therefore, according to this calculation, storage operation is not economically feasible and would not provide any operating savings. To check the validity of this calculation, the benefit to cost ratio of operating the storage unit is explicitly calculated as:

$$B/C = \frac{\textit{Operating Savings of Energy Storage}}{\textit{Operating Costs of Energy Storage}}$$

The operating savings and costs of energy storage depend on the operations of the storage unit. One operating option is to charge during the off-peak period and discharge during the peak period to replace Unit A (we assume that there is enough power available during the off-peak period to provide the energy required for charging the storage unit and to replace the off-peak energy output of Unit A). The benefit to cost ratio of this operating option is calculated as follows:

$$\text{Required Charging} = \frac{100 \text{ MW x } 8 \text{ hrs}}{0.77} = 1{,}039 \text{ MWh}$$

$$\text{Charging Costs} = 1039 \text{ MWh x } \$17/\text{MWh}$$
$$= \$17{,}663$$

Required Off-Peak
Energy Replacement = 50 MW x 16 hrs = 800 MWh

Costs of Replacing
Off-Peak Energy = 800 MWh x $17/MWh
= $13,600

Total Costs of
Replacing Unit A = 17,663 + 13,600 = $31,263

Total Savings by
Replacing Unit A = Total Operating Costs of Unit A
= 100 MW x 8 hrs x $21/MWh
+ 50 MW x 16 hrs x $25/MWh
= $36,800

The benefit to cost ratio of operating the storage unit to replace Unit A is therefore:

$$B/C = \frac{36{,}800}{31{,}263} = 1.177$$

Therefore, storage operation is economically feasible and would provide the system with operating savings. The implied dynamic operating benefits term, μ, which is missing from the conventional equation, can be calculated as:

$$B/C = 1.177 = 0.77 \frac{18.0 + \mu}{17.0}$$

or

$$\mu = \frac{1.177 \times 17.0}{0.77} - 18.0 = \$7.98/MWh.$$

Spinning Reserve Application

As an alternative to using the battery as a charge/discharge unit, a utility could use a battery purely to provide spinning reserve with the following potential benefits: shut down least efficient units and allow generating units to operate at a higher load, thus reducing their average heat rates.

The following example illustrates the benefits from using a battery as spinning reserve. Consider a system consisting of three thermal units (Units 1, 2 and 3). System load is 200 MW, and spinning reserve of at least 40 MW is required. Table 2-2a shows the system dispatch without a battery. Without a spinning reserve requirement, units 1 and 2, the most efficient units, would have been able to meet the system load of 200 MW. Because of the spinning reserve requirement, all three units are operated; units 1 and 2 operate at 90 MW each and unit 3, the least efficient, is operated at its minimum load of 20 MW.

Table 2-2
USING A BATTERY TO PROVIDE SPINNING RESERVE

(a) Unit Loadings and Operating Costs Without Battery

	Min. Load (MW)	Max. Load (MW)	Ave. Cost at Max. Load ($/MWh)	Actual Load (MW)	Ave. Cost at Actual Load ($/MWh)	Spinning Reserve (MW)	Total Cost ($/hr)
Unit 1:	20	100	24.5	90	25	10	2,250
Unit 2:	20	100	24.5	90	25	10	2,250
Unit 3:	20	40	30	20	40	20	800
Total						**40**	**5,300**

(b) Unit Loadings and Operating Costs With Battery

	Min. Load (MW)	Max. Load (MW)	Ave. Cost at Max. Load ($/MWh)	Actual Load (MW)	Ave. Cost at Actual Load ($/MWh)	Spinning Reserve (MW)	Total Cost ($/hr)
Unit 1:	20	100	24.5	100	24.5	0	2,450
Unit 2:	20	100	24.5	100	24.5	0	2,450
Unit 3:	20	40	30	0	0	0	0
Battery:	0	40	0*	0	0*	40	0
Total:						**40**	**4,900**

* The operating cost of a battery providing only spinning reserve is really the fuel cost of keeping the battery charged. However, this cost is negligible in this context.

Dynamic operating costs resulting from the spinning reserve requirement are of two types. First, there is the cost of operating Units 1 and 2 at other than their most efficient level. Second, there is the extra cost of operating Unit 3, which is the difference between the average generation cost at Unit 3 and what it would have cost to generate the same load at Units 1 and 2.

Adding a battery changes the system operation, as displayed in Table 2-2b. Units 1 and 2 can now operate at full capacity, and Unit 3 is shut down entirely; the battery provides the required spinning reserve. For the particular hour shown in the tables, the savings per MWh of spinning reserve is ($5300 – $4900)/40 MWh = $10/MWh.

The spinning reserve benefits of using a battery in this manner can be summarized as follows: Unit 3, the least efficient unit, can be shut down and units 1 and 2 do not have to provide spinning reserve, and can operate at their most efficient loadings. The battery provides all required spinning reserves, and the system total operating costs are substantially lower.

STUDY APPROACH

The potential generation benefits from adding battery storage to the SDG&E system were determined by examining actual system operating log records for eight representative days during 1990-1991, a weekday and a weekend day in each season. The study focused on the marginal units (defined below) on these eight days and determined how the operation of these units could be economically modified if sufficient battery storage were present on the system. Two potential applications of batteries were considered:

- Daily charge/discharge with three hours of storage
- Spinning reserve

Hourly system loads for the eight days are shown in Appendix B. For most of the days, the daily peak occurs between 5 pm and 8 pm. The peak appears sharp enough that a battery of 200-300 MW and a three-hour storage capacity could shave 200-300 MW off the peak on these days. This is not the case on the summer weekday, when the peak occurs earlier in the day and is much broader.

The SDG&E hourly marginal energy costs (system lambda) for the same eight days, shown in Appendix B,[1,2] generally change very little during a 24-hour period. Typically, however, system marginal energy costs are substantially lower during the off-peak hours than during on-peak hours. For SDG&E, differences between days are larger than the differences within each day. The primary reason for the differences between days is variation in natural gas prices, from a low of $2.11 per million Btu in summer to a high of $3.73 per million Btu in winter.

Generating benefits of energy storage were calculated based on five gas-fired steam turbine units on the SDG&E system for each of the eight days. These five units were selected as the marginal units whose operation would most likely be affected by the addition of batteries to the system. That is, they would be potential candidates for decommitment. Larger gas-fired and nuclear units were excluded because they were too large to be replaced by batteries. Smaller units, including combustion turbines, were excluded because they did not operate at all

1. The hourly marginal costs are for on-system units only. Including off-system purchases (typically available at costs lower than system costs, particularly during off-peak hours) could only increase the potential storage benefits calculated here (because the costs of charging the battery would be reduced).

2. System load shapes, hourly marginal costs, and information on individual units were all provided by SDG&E.

on the eight days considered. The key cost/performance characteristics of these five units are shown in Table 2-3.

Table 2-3
SDG&E GENERATING UNIT CHARACTERISTICS

Unit	Min. Load (MW)	Max. Load (MW)	Hot Startup Cost ($)	Heat Rate at Min. Load Btu/kWh	Heat Rate at Max. Load Btu/kWh
Encina 2	20	104	2500	13,343	10,832
Encina 3	20	110	2500	13,872	10,957
South Bay 1	30	147	3500	12,142	9,904
South Bay 2	30	150	3500	12,073	9,788
South Bay 3	30	171	3500	14,308	10,361

STUDY RESULTS

Load-Leveling Benefits

For load-leveling, a battery with three hours storage capacity was assumed to be charged at night and discharged during the daily peak. Actual system lambdas were used to calculate potential savings or benefits. For a three-hour battery with an efficiency of 80 percent, load-leveling savings were negative for all 8 days. As shown in Figures B-5 to B-8, system lambda is relatively flat across the 24 hours in each day, because the same gas-fired steam turbines are the marginal units for all 24 hours, although at different loadings. As a result there are no load-leveling savings from the use of batteries on the SDG&E system. Unless there were other reasons for operating the battery in this mode, it would simply not be operated, making load-leveling savings zero.

Many previous studies on energy storage have used only the load-leveling savings in quantifying the value of energy storage. Doing so here would lead to the conclusion that batteries are clearly uneconomic, and should not be considered further. As shown below and in the next sections, however, there can be significant savings from batteries even if load-leveling is uneconomic.

Dynamic Operating Benefits

The generation benefits resulting from adding batteries to the SDG&E system are summarized in Tables 2-4 and 2-5. Table 2-4 shows, for each of the eight days considered, the dynamic operating savings that could be realized if enough battery capacity were added to completely decommit the unit labelled "displaced unit".

Table 2-4
SUMMARY OF GENERATION BENEFITS
—NET OPERATING BENEFITS—

					Application			
					3 Hour Charge/Discharge		Spinning Reserve	
Season	Month	Day	Day Type	Date	Net Oper. Saving ($/KW-yr)	"Displaced Unit"	Net Oper. Saving ($/KW-yr)	"Displaced Unit"
Fall	October	Sunday	W-End	10/14/90	14.09	South Bay 3	15.84	South Bay 3
Fall	October	Friday	W-Day	10/19/90	11.22	Encina 3	14.16	Encina 3
Winter	December	Tuesday	W-Day	12/04/90	59.87	Encina 2	63.92	Encina 2
Winter	December	Saturday	W-End	12/08/90	39.50	South Bay 3	44.97	South Bay 3
Spring	April	Monday	W-Day	04/08/90	25.94	Encina 3	28.68	Encina 3
Spring	April	Saturday	W-End	04/13/90	15.55	Encina 2	20.59	Encina 2
Summer	July	Sunday	W-End	07/21/90	7.85	South Bay 3	11.97	South Bay 3
Summer	July	Wednesday	W-Day	07/24/90	0.00	—	3.68	South Bay 2
Estimated Annual Net Operating Savings					23.23		26.89	

Table 2-5
LOAD LEVELING SAVINGS, DYNAMIC OPERATING BENEFITS, NET OPERATING BENEFITS

					3 Hour Charge/Discharge		
Season	Month	Day	Day Type	Date	Load-Leveling Benefits ($/MWh)	Net Operating Benefits ($/MWh)	Dynamic Operating Benefits ($/MWh)
Fall	October	Sunday	W-End	10/14/90	-2.30	22.77	24.06
Fall	October	Friday	W-Day	10/19/90	-2.36	19.11	21.54
Winter	December	Tuesday	W-Day	12/04/90	-3.56	73.85	76.25
Winter	December	Saturday	W-End	12/08/90	-3.74	59.12	64.02
Spring	April	Monday	W-Day	04/08/91	-3.31	43.44	46.91
Spring	April	Saturday	W-End	04/13/90	-3.78	31.88	40.85
Summer	July	Sunday	W-End	07/21/91	-3.35	12.77	17.92
Summer	July	Wednesday	W-Day	07/24/91	-2.78	0.00	0.00

Two operating modes or applications are considered: a three-hour battery that is charged and discharged on a daily basis, and a battery with a smaller storage capacity that is used to provide only spinning reserve. On each day and for each operating mode a "displaced unit" is identified; this is the unit for which the greatest savings could be obtained by decommitting the unit. The columns labelled "net operating benefits" express the savings in terms of dollars per year per kilowatt of battery capacity, assuming that the battery is the same size as the displaced unit and that all 365 days of the year were identical to the one for which the calculation is being made. The "annual net operating benefits" values are weighted averages of the daily values, based on the number of weekdays and weekend days in each season during an entire year.[3]

As defined in Table 2-4 and 2-5, net operating benefits include all dynamic operating benefits (startup costs savings, load following cost savings, minimum load cost savings), less increased costs resulting from having to charge the battery for the daily charge/discharge operating mode. For the spinning reserve operating mode, the net operating savings are simply the reduction in total operating costs. Because the load-leveling savings are negative on each of the eight days, net operating savings are less in charge/discharge mode than in spinning reserve mode on each day.

Most of the dynamic operating cost savings on the SDG&E system result from reductions in load following costs and minimum loading costs. Load following costs for the SDG&E units considered in this study are on the order of thousands of dollars per day for each of the five marginal units. Minimum load costs are on the order of hundreds of dollars per day for each of the five units. Figures 2-5 and 2-6 show the actual MW loadings for two of the marginal units for the days on which the dynamic operating cost savings would be greatest from decommitting these units. Most of the time the units operate far from their most efficient loadings (96 MW for Encina 2 and 136 MW for South Bay 3).

Since this study is based on data from a selection of discrete days (a week-day and a weekend-day for four different weeks), the only startups accounted for are those taking place within a 24 hour period, i.e., only hot startup costs. However, three out of the four sample weeks show that at least one unit is shut down and replaced by another sometime between the two days examined in that week. As a result, the startup costs may be under-estimated, because they miss these changes between days. There were very few startups on the eight days in generation, so startup cost savings are a very small part of the net operating savings shown in the tables.

The same results are expressed in a different format in Table 2-5, for the 3 hour charge/discharge mode. Instead of on a $ per kilowatt per year basis, the results are expressed in $/MWh displaced during the three hours that the battery is discharging. The important point here is that the magnitude of the dynamic operating benefits is much larger than the magnitude of the load-leveling savings. These numbers can be compared to system marginal energy costs, which are mostly in the range of $20 to $30 per MWh; as a result of decommitting a unit, savings higher—sometimes much higher—than system marginal energy costs are possible.

3. The definitions of the seasons were as follows:

Fall	October 16-November 30
Winter	December 1-February 28
Spring	March 1-June 30
Summer	July 1-October 15

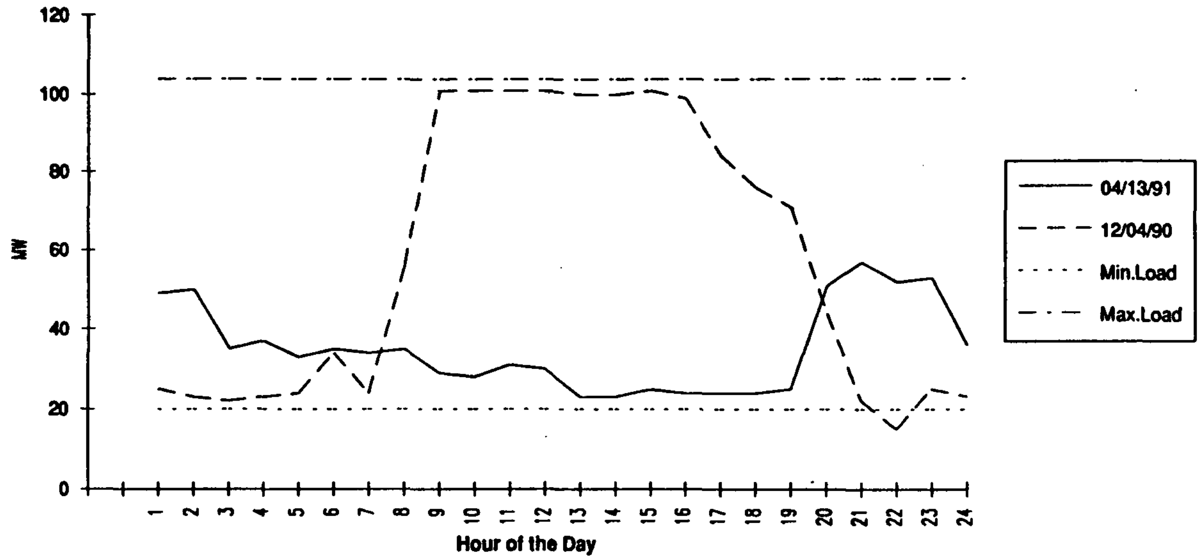

Figure 2-5. Daily Load for Encina 2 Steam Turbine Unit

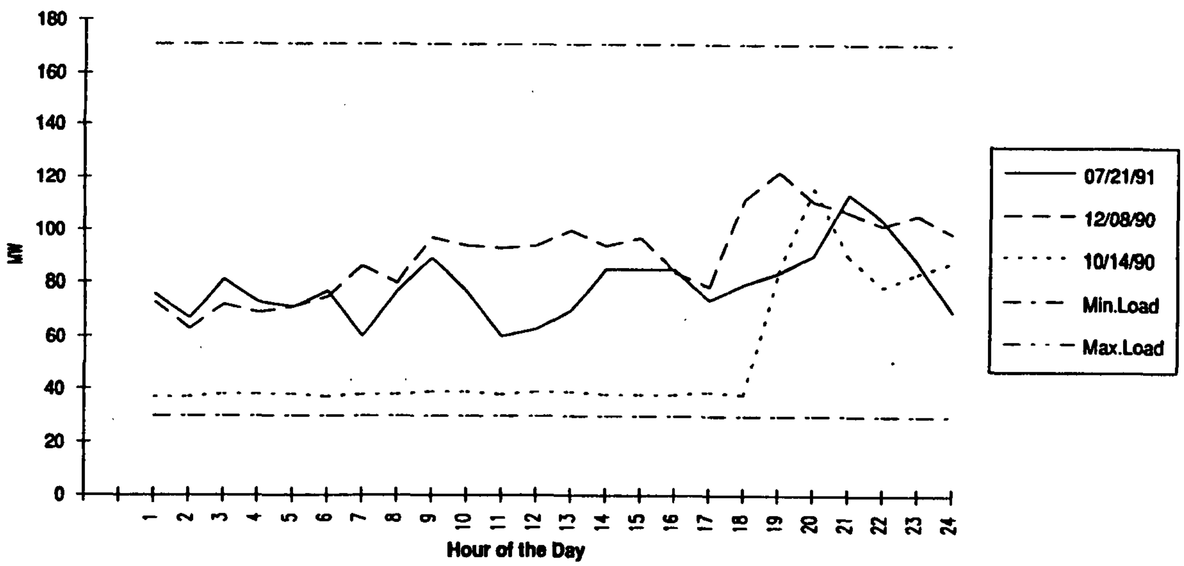

Figure 2-6. Daily Load for South Bay 3 Steam Turbine Unit

The same information is also presented in Figures 2-7 and 2-8. Figure 2-7 shows how net operating benefits savings vary by day, in dollars per kilowatt per year if all 365 days looked just like the day in question. Figure 2-8 presents the information in terms of dollar per MWh displaced by the battery during the three hours the battery operates. Savings are highest in winter, lowest in summer, and intermediate in spring and fall.

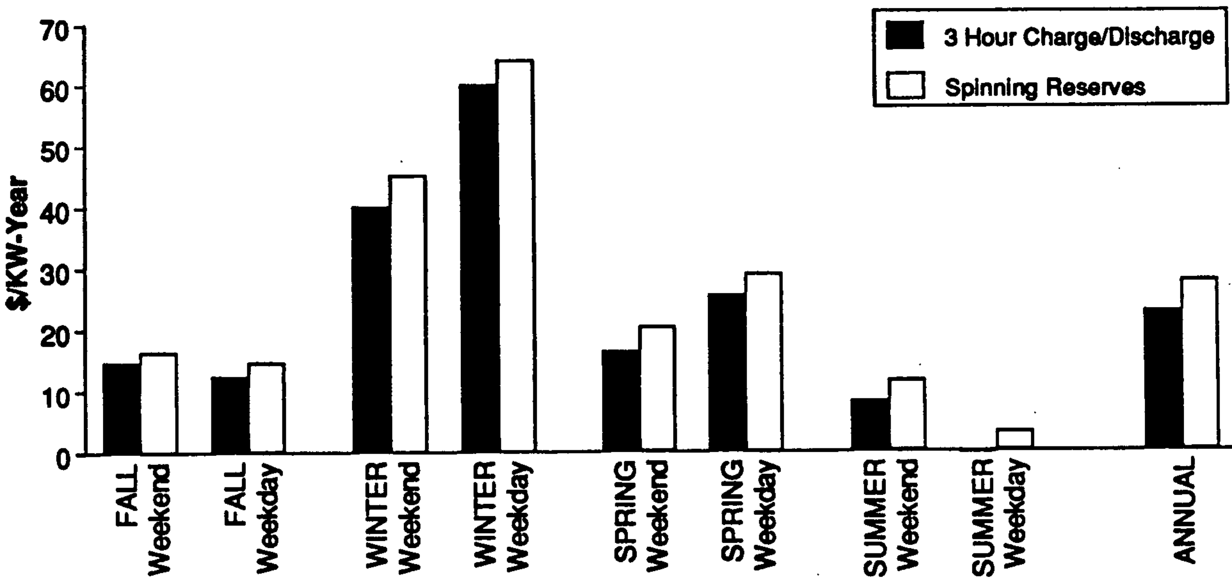

Figure 2-7. Net Operating Benefits

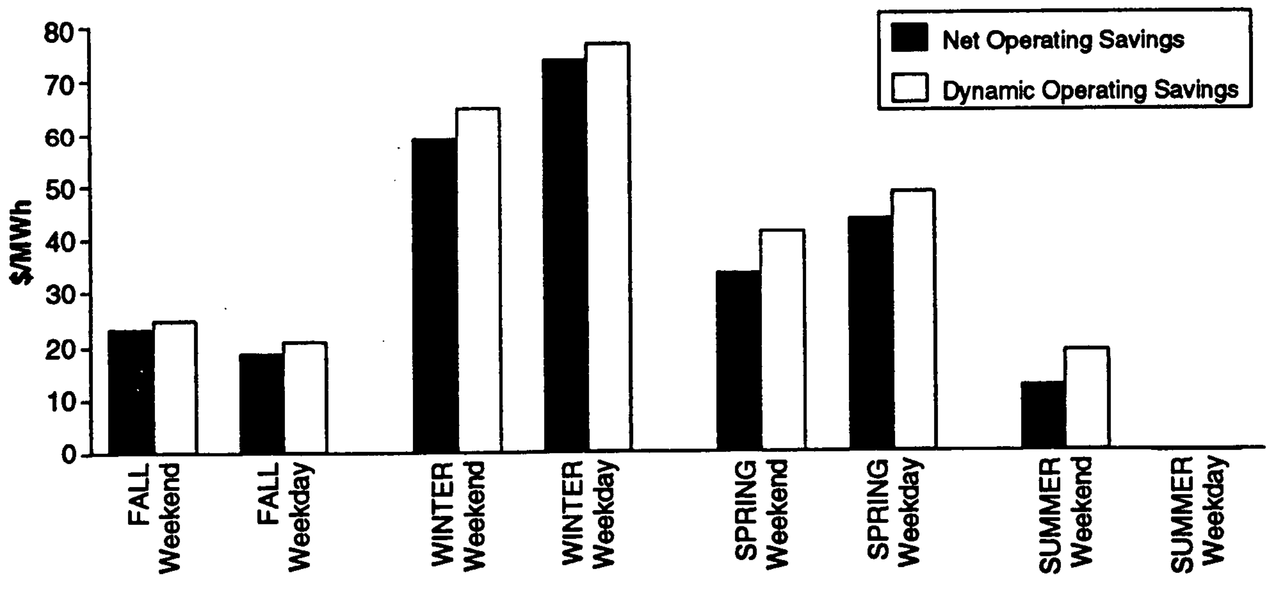

Figure 2-8. Net Operating Benefits for 3 Hour Charge/Discharge Battery

Why do the net operating benefits vary so much between days? There are two principal reasons. First, the biggest difference results from changes in fuel prices. Higher fuel prices mean higher system lambdas and higher average fuel costs. Since net operating benefits is roughly proportional to the difference between average fuel cost and system lambda, both of which are roughly proportional to fuel price, higher fuel prices translate directly to higher net operating savings. The second reason is the difference between average fuel cost and system lambda. This difference depends on many factors, among them fuel prices and unit loadings. The greater the difference, the greater the net operating savings. The difference is particularly small on the two summer days, resulting in low net operating savings on the weekend day and no operating savings at all on the weekday.

Keep in mind that all of the calculations assumed that any replacement energy or capacity would come from on-system units. This potentially underestimates the savings from adding batteries and should be considered a conservative approach.

If a steam turbine unit is decommitted as the result of adding batteries, combustion turbines are likely to be used more frequently in outage situations, rather than increasing the loadings of committed steam turbines. This may slightly reduce the dynamic operating savings resulting from changing the unit commitment. For example, if the addition of 100 MW of batteries causes a 100 MW combustion turbine to operate 100 hours more per year and has an average heat rate of 3000 Btu/kWh higher than that of the decommitted steam turbine, the increased cost would be $0.75/kW of battery capacity per year.[4]

Environmental Benefits

Storage in general, and batteries in particular, have the potential to reduce the environmental emissions associated with generation. By allowing operation of fossil-fired units closer to their most efficient operating loadings, batteries can reduce system emissions. They can also allow the substitution of one fuel for another or one generating location for another. In determining the environmental impacts of adding batteries, it is critical to determine the locations, fuel types, and marginal heat rates for the unit that would be used to charge the battery and the unit that would be replaced by the battery, for load-leveling operation. Fuel type is obviously important because different fossil fuels have different emission coefficients, while nuclear and hydro emit no NO_x, SO_x, or CO_2. Location is important, especially for NO_x, because NO_x emissions in a densely populated urban area such as San Diego may be much more harmful than an equal amount of emissions in a sparsely populated area such as northern Arizona.

Consider the potential benefits from a battery used only to provide spinning reserve, assuming that only on-system units are affected. The externality value of NO_x emissions is $1-12 per pound, while the current emission rate for NO_x from SDG&E gas-fired units is 1-1.5 pounds per MWh.[5] Assuming that the addition of batteries improves generation efficiency by 10

4. $\dfrac{\text{100 MW CT x 100 hours/year x 3000 Btu/kWh x \$2.50/million Btu}}{\text{100 MW batteries}}$

5. Values provided by Harry Bishop, SDG&E.

percent, at a capacity factor of 60 percent, the battery provides NO_x reduction benefits of $1 to $10 per kW of battery capacity per year.[6]

This approximate calculation is based on current NO_x emission rates. It is likely that regulations may require retrofitting control equipment that will sharply reduce these emission rates. Adding batteries to the system could make it unnecessary to add expensive controls such as selective catalytic reduction (SCR) to a generating unit whose utilization would be sharply reduced by the addition of batteries. Avoiding the costs of SCR for a unit could be worth substantially more than the $1-10/kW-year calculated above.

6. $1-12/lb x 1-1.5 lbs/MWh x 0.1 x 0.6 x 8760 hrs/year x 1 MW/1000 kW ≈ $1-10/kW-year.

3

POTENTIAL TRANSMISSION SYSTEM BENEFITS

NEW TRANSMISSION PROJECTS

In general, the primary purpose of the bulk power transmission system is to reliably deliver power from local and remote generating units to the utility load centers; in this case, the city of San Diego. Future transmission systems must provide adequate capability to accommodate expected power purchases from remote generation sources as well as deliver power from local generation to SDG&E customers. New transmission additions are a function of both the generation or resource expansion plan adopted by San Diego Gas and Electric (SDG&E), and the areas of high load growth.

The preferred San Diego Gas and Electric plan of resource additions in its biennial resource plan update (BRPU) appears to consist primarily of adding or repowering generation locally. At this time, review of existing transmission expansion plans with the transmission planning department indicates that there are a limited number of anticipated or potentially needed transmission additions based on this local generation expansion plan. In fact, the resource expansion plan is so recent that transmission planning studies corresponding to the BRPU have not been completed. Hence, there were no specific major transmission facility additions to the SDG&E system over the near term planning horizon that could be targeted for this study.

One potential SDG&E 69 kV transmission expansion project, to add a line in 1994 into a substation serving approximately a 35 MW peak load, was identified.[1] Two alternative 69 kV transmission expansion plans have been identified to serve this need. The first alternative is to add 2 1/2 miles of 69 kV line at a cost of approximately $4 million, with 1 1/2 miles consisting of underground construction and 1 mile consisting of overhead construction. The second alternative is to install an underwater feed from a remote power source at a cost of $10 million.

Although the transmission system expansion plans for SDG&E over the near term horizon are incomplete at this time, SDG&E planners indicated the potential need for new short 69 kV and 230 kV transmission lines with line lengths ranging up to about 15 miles. No new 500 kV lines are anticipated. Hence for this study, potential line deferral benefit calculations for new 15 mile 69 kV and 230 kV (generic) transmission line additions are evaluated to estimate the potential transmission line deferral benefit to SDG&E.

1. SDG&E prefers to not release details regarding this substation or the customers it serves.

TRANSMISSION SYSTEM RELIABILITY CRITERIA

The need for new transmission facilities will be generally determined by SDG&E transmission planning on a case by case basis, based on the evaluation of a number of appropriate design contingencies. The objective of these transmission planning studies is to provide a reliable system considering appropriate outage criteria, risks and costs. The SDG&E transmission system is normally designed to meet or exceed the following basic reliability criteria.

The basic transmission system reliability criteria for 69 kV consists of designing for a single contingency outage at annual system peak. For transmission voltages above 69 kV, the basic SDG&E transmission system single contingency reliability criteria is increased to include appropriate double contingency outage criteria, including outage considerations selected on a case by case basis, such as two lines or a transformer and line, etc. out of service at the same time. The basic transmission system voltage criteria is to maintain a 0.95 per unit minimum voltage level during normal operating conditions and a 0.9 per unit voltage level during an abnormal contingency event.

POTENTIAL LINE AND TRANSFORMER DEFERRAL BENEFITS

In future specific line and transformer deferral studies, determining potential battery benefits will require detailed transmission expansion studies. These studies will need to evaluate appropriate transmission equipment outages with and without batteries in specific transmission system locations. They will also need to recognize the significant differences between batteries and lines and transformers in terms of their contribution to reliability. The resulting transmission expansion plans with and without batteries will have to meet appropriate SDG&E transmission and reliability standards, described above.

For this generic assessment, judiciously placed batteries are assumed to provide a local power source near loads that can act as backup to existing transmission facilities and thereby reduce the transmission redundancy required to meet SDG&E transmission reliability criteria. The batteries are, effectively, spinning reserve, but are used to cover transmission outages. For this application, judiciously placed batteries may provide the desired transmission deferral benefit while at the same time providing additional non-site-specific generation system benefits.

SDG&E standard transmission line voltages are 500 kV, 230 kV, 138 kV and 69 kV. As stated previously, presently there are no plans for new 500 kV transmission line additions. For this study, potential benefits of adding battery storage to defer new generic 15 mile 230 kV lines and 69 kV lines will be evaluated, along with the potential savings associated with deferring the proposed 1994 69 kV expansion project described above.

SDG&E transmission line cost assumptions for typical 69 kV and 230 kV line construction types are summarized in Table 3-1. These assumptions are derived from detailed transmission facility cost and other assumptions obtained from SDG&E transmission planners and presented in Appendix A. Since new line right-of-way (ROW) is difficult to obtain and costly, battery storage benefits associated with both underground (UG) and overhead (OH) 69 kV line designs are being evaluated in this study. In addition, it is likely that most new 230 kV lines will consist of double circuit steel pole construction because of ROW limitations and costs.

Table 3-1
TYPICAL SDG&E TRANSMISSION LINE COST

Transmission Line Construction Type	1990 Dollar Installed Cost ($1000/mi)*
69 kV, Underground, 1750 AL	
New Conduit	1,419
Existing Conduit	567
69 kV, Wood Pole, 1-1033.5 ACSR/AW	
Single Circuit	178
Double Circuit	320
230 kV, Double Circuit, Steel Pole, 2-1033.5 ACSR/AW	
Single Circuit	1,158
Double Circuit	1,389

* Without Land Cost

Typical ROW width and land cost data for single pole transmission line construction are presented in Table 3-2. These land cost assumptions are based on the current ROW purchase costs obtained from the SDG&E land purchase department. The low land cost assumption of $0.50/ft.^{2} applies to new lines installed in rural desert areas, while the high land cost assumption applies to higher land value areas, which are prevalent in the SDG&E service territory. ROW cost will apply to portions of new lines installed outside of the SDG&E City of San Diego franchise area.

Table 3-2
TYPICAL SDG&E ROW WIDTH AND LAND COST

Line Voltage	Typical ROW Width[1]	High ROW Cost[2] ($1000/mi)	Low ROW Cost[3] ($1000/mi)
69 kV Line	24'	2,534	63
138 kV Line	30'	3,168	79
230 kV Line	50'	5,280	132

1. Single Pole Construction along a road
2. Based on $20/ft.^{2}
3. Based on $0.50/ft.^{2}

For this study, batteries installed on the SDG&E system are expected to be installed at the 12 kV distribution primary level or higher. Thus, potential transmission line deferrals are expected to apply to new transmission lines of 69 kV and above. Potential bulk power transformer deferrals are expected to include both 230/138 kV and 230/69 kV transformer banks. Example transmission deferral benefits are considered for 230 kV transmission lines, 230/69 kV bulk power transformer banks, and 69 kV lines in this section. Deferral of 69/12 kV distribution substation transformer banks and 12 kV feeders are considered in Section 3.

Potential line and transformer deferral benefits resulting from judicious placement of batteries on the SDG&E system are summarized in Table 3-3 for typical economic assumptions used in current SDG&E transmission planning studies. For the proposed 1994 69 kV project potential annual line deferral benefits range from $654,000 per year to $1,635,000 per year depending on the selected transmission alternative being deferred. For other potential 15 mi 69 kV line additions, annual line deferral benefits range from $591,000 per year to $8,361,000 per year. For potential 15 mi. 230 kV line additions, annual line deferral benefits range from $3,163,000 per year to $16,356,000 per year. And if a potential 224 MVA 230/69 kV transformer addition (in an existing substation without ROW) can be deferred, annual benefits range from $1,039,000 per year to $1,116,000 per year. Note that ROW costs dominate capital investment requirements for new SDG&E transmission in much of the SDG&E service area and are the cause of the wide line cost variations.

Table 3-3
POTENTIAL BENEFIT FROM DEFERRING NEW TRANSMISSION FACILITIES (1990 dollars)

Line and Transformer Description	Total Capital Investment ($1000)	Annual Benefit[1] ($1000/yr)
Proposed 1994 69 kV Project, Alt. 1 - 2.5 mi Line Ext	4,000	654
Proposed 1994 69 kV Project, Alt. 2 - Underwater Feed	10,000	1,635
69 kV, 15 mi. OH, Low ROW, Single Circuit	3,615	591
69 kV, 15 mi. OH, Low ROW, Double Circuit	5,745	939
69 kV, 10 mi. OH, 5 mi. UG, High ROW, Single Circuit	46,885	7,666
69 kV, 10 mi. OH, 5 mi. UG, High ROW, Double Circuit	51,410	8,361
230 kV, 15 mi. OH, Low ROW, Single Circuit	19,350	3,163
230 kV, 15 mi. OH, High ROW, Single Circuit	96,570	15,789
230 kV, 15 mi. OH, Low ROW, Double Circuit	22,815	3,730
230 kV, 15 mi. OH, High ROW, Double Circuit	100,035	16,356
230/69 kV 224 MVA Transformer, 3 Breakers	6,354	1,039
230/69 kV 224 MVA Transformer, 4 Breakers	6,826	1,116

Potentially large transmission savings are indicated by these numbers, especially when costly ROW is required. Significant benefits may accrue where batteries can be judiciously placed on the SDG&E system to defer specific line and transformer additions under SDG&E planning design conditions. However, quantifying line and transformer deferral benefits of batteries will require comparative planning studies with and without batteries.

For example, assume SDG&E has a 69 kV/12 kV distribution substation with a current annual 68 MVA peak load, presently being served by two 69 kV transmission lines, each containing single 336 MCM ACSR conductors with a line rating of 68 MVA. SDG&E's transmission reliability criteria indicates that with either 69 kV line out of service the other 69 kV line must be capable of serving the annual peak load. Hence, any distribution substation load growth will require an additional 69 kV line to reliably serve this distribution substation. Assuming the worst case, an expensive new 15 mile 69 kV line (10 mi. OH and 5 mi. UG in Table 3-3) may cost up to $51,140,000. Assuming a discount rate of 11.6% and a fixed charge rate of 16.35%, the resulting (PWRR) present worth of revenue requirements to perpetuity are about $72,081,000.

Assume that SDG&E plans to install a 20 MW battery and judiciously locates the battery at this substation. This battery can provide an alternate source of power, and satisfy SDG&E's single contingency reliability criteria until the annual peak substation load increases an additional 20 MW. At 3% per year load growth, the new expensive 15 mile 69 kV line addition can be deferred about nine years, saving over $8 million per year in annual fixed charges for the nine years. Assuming 4% inflation, the resulting PWRR associated with deferring the expensive new 15 mi. 69 kV line is $38,207,000 resulting in a line deferral PWRR savings benefit of $33,874,000.

On a capital investment basis, this example transmission deferral benefit translates, after accounting for the PWRR and discounting calculations, into a battery storage credit of up to $1200/kW for the 20 MW battery depending on cost of the new line addition being deferred. If the expensive new line were constructed with only one circuit strung the resulting battery storage benefit would still be about $1100/kW for the 20 MW battery.

The specifications for a battery to defer this 15 mile 69 kV line will depend heavily on the substation load shape. If the substation load shape is similar to the system-wide load shape, 6 or 8 hours of storage may be needed to cover the 20 MW load growth. However, most substations do not exhibit the system-wide load shape. Figure C-2 in Appendix B shows one example of a substation load shape. Comparing it with Figure C-1 shows that individual substations can be different from the system-wide load shape. This example is the SDG&E Cabrillo substation which serves a Navy base. This load is essentially an industrial load and exhibits the relatively flat day time load profile when load is high. In spite of it being an industrial type of load, a 2 to 3 hour peak does occur on the annual peak day. Residential loads tend to exhibit an evening peak, and, where air conditioning is a large share of the load, an afternoon peak. If the substation in question above has a several hour peak on the peak load day, a 2 to 3 hour battery would be sufficient to defer the 15 mile 69 kV line for some years. Though load shape data is not available for a range of individual SDG&E substations, it is anticipated that many will exhibit load shapes that would require less than four hours of battery energy storage to meet line deferral requirements.

A battery that is to "back-up" a transmission line must be recharged while the line is out if the failed line must remain out of service for several days. In the example above, each line is capable of 68 MVA, and the battery is suggested to cover only 20 MW of load growth, or provide for a total substation load of 88 MVA. To do this the load must drop below 68 MVA at night for a time sufficient to allow the battery to be fully recharged as shown in the example in Figure 3-1. In this example there is ample time to recharge the battery. However, it is clear that the load profile could limit use of a battery if the substation load factor is high. The load profile is thus a key parameter in determining how long a line or transformer can be deferred.

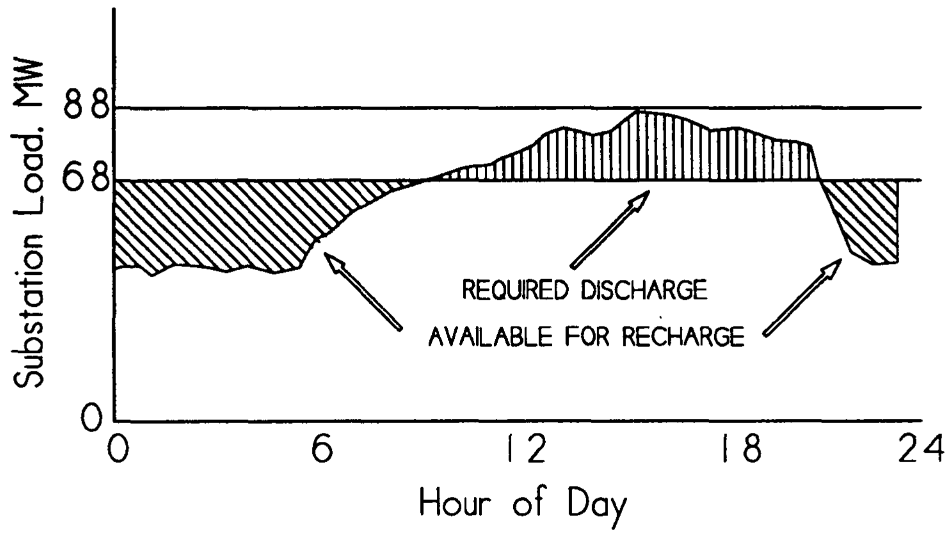

Figure 3-1. Load Shape For Battery Recharge at Substation

LOSS REDUCTION

As part of a transmission system benefit assessment or other battery application benefit assessment, relative transmission losses with and without battery storage should be considered. Batteries can reduce transmission losses by shifting load from the peak period to the off-peak period. This results from the square law that governs resistive losses. Reducing transmission system loading during daily peak load times by discharging batteries reduces peak load losses by more than they are increased at night when the batteries are recharged.

The potential loss reduction benefit is fully available only if batteries are *not* used to defer transmission. When transmission is deferred, it is possible for batteries to increase losses and cause a loss penalty. This can occur if the load shape is significantly flattened by batteries, so that average transmission loading is high. The levels of battery penetration that are likely in the foreseeable future will usually reduce losses.

Evaluation results for the relative magnitude of system losses is expected to vary for specific battery storage applications on the SDG&E system. Previous experience indicates that the magnitude of the potential loss benefit or penalty can vary widely, and must be evaluated on a case by case basis.

There are a number of important issues which should be considered before determining whether relative losses need to be considered, and if so, how detailed an evaluation will be required.

First, if the proposed application requires the battery to be cycled frequently, consideration of losses will be more important than in applications where the batteries are to be cycled only occasionally, or where only small amounts of energy are involved. Of course, if the loss benefits themselves are significant, they should be a factor in determining the frequency of cycling.

Second, the location of the generation used to charge the batteries and the location of the generation displaced when the batteries are discharged will each have a significant impact on the relative magnitude of the losses and resulting relative cost of losses.

Third, on a site-specific basis the daily load shape characteristics of the local transmission system in the vicinity of the battery and the daily battery charge discharge cycle may or may not be similar to the native daily SDG&E load shape. Section 2 contains plots of SDG&E daily native load shapes for typical weekdays and weekend days in the spring, summer, fall and winter seasons over the past year. Appendix B contains plots of daily loads at one of SDG&E's distribution substations during summer and winter peak load days. Note that the daily load shapes differ significantly. When the two are different, the loss reduction near the battery may be higher than the loss reduction in the bulk systems. However, so long as the substation peak falls within the system native load peak, both portions of the system will experience lower losses when the battery is cycled.

In battery storage applications where transmission loss benefits are to be determined, the best available marginal generation costs and corresponding marginal loss factors should be determined. Appendix B contains plots of SDG&E's daily native load shapes and corresponding hourly SDG&E system marginal energy cost. Although the daily load shapes fluctuate significantly, the hourly marginal generation costs are relatively constant on a daily on-peak/off-peak basis for the different seasons. Thus, on the SDG&E system, relative cost of transmission losses may be quickly estimated using incremental on-peak/off-peak transmission loss calculations, without resorting to hourly production simulation.

For example, the SDG&E on-system peak transmission losses are about 2% of system load. That is, losses are about 40 MW when system load is at 2000 MW. Incremental losses are thus about 4%. Hence reducing peak load by 10 MW would reduce losses by 0.4 MW or 400 kW. The system load is about 1000 MW at low load, and losses are about 0.5% (about 2% incremental). Charging the battery at night would thus cause losses of about 200 kW. Taking into account battery efficiency, about 160 kWh of energy is saved for each hour the battery is discharged during the load peak and charged at night.

The above estimates consider only the reduction of losses on SDG&E owned lines. Much of the power imported by SDG&E is transported over long lines from Arizona and New Mexico. Though losses associated with this long-distance transmission are not recognized by SDG&E, they nevertheless do occur and are included in the cost of energy purchased by SDG&E. A full accounting of the loss reduction available from shifting transfers from peak periods to off-peak periods would have to include an analysis of all parties to the transaction. It would also have to take into account the way loss costs are distributed among the transmission system users. Because loss costs are shared among several users, their true impact is not recognized. That is, no party is acknowledged to be responsible for the incremental transfer and the incremental losses that can reach 20 to 30%.

The peak load losses on the lines from Arizona to California are on the order of 20 to 25% incremental. A 10 MW battery would thus save 2 to 2.5 MW of losses if it were used to reduce flows from Arizona to California under high transfer conditions. However, the lines from Arizona to California remain fairly heavily loaded at night, so there is only modest savings by shifting energy transfer from peak periods to off-peak periods. Nevertheless, the loss reduction could be very significant if it could be determined and credited to the battery.

VOLTAGE REGULATION

Regulation is the drop in voltage that occurs when a load is thrown on the system. The larger the voltage change, the poorer the regulation. When system impedance is high (the system is weak), regulation will be poor. Adding lines and transformers can strengthen the system, but are a costly way to solve poor voltage regulation problems. Conventional voltage control devices such as generators, synchronous condensers, switched capacitor banks, static var systems (SVS), and load tap changers on transformers 'regulate' voltage and improve regulation. The voltage regulation response times for the various voltage control devices are:

LTC	1 to 2 minutes
Capacitors	1 to 2 minutes
Generators	1 to 2 seconds
Condenser	1 to 2 seconds
SVS	0.1 to 0.2 seconds

The SVS is clearly the most effective because it is so quick. An SVS consists of some combination of thyristor switched shunt capacitors and thyristor controlled shunt reactors. An SVS can respond to a drop in voltage before it becomes a problem for voltage-sensitive equipment or before a person can see the voltage drop in the light output of fixtures. Generators are often located too far from the load to be useful. Condensers are no longer competitive compared to SVS. LTCs and capacitors are slow, but are economical and very effective at combating slow changes in voltage, such as those resulting from normal load variations.

Judiciously placed batteries can improve voltage regulation in two ways. One is by supplying power locally when heavy transmission loading or transmission outages are the cause of the low voltage. Increasing battery power to reduce line loading will improve voltage. Each MW of battery power is typically equivalent to 2 to 3 Mvar of reactive power in terms of its impact on voltage.

Batteries can also improve voltage regulation through reactive supply from their gate-turn-off (GTO) or similar power converters. The converters between the ac system and the battery dc bus can be designed to behave like an SVS while charging or discharging the battery. A modest increase in converter rating, over that required to supply full battery power, is necessary to supply reactive power during charging or discharging operation. For example, an 11 MVA converter on a 10 MW battery can provide up to 4.6 Mvar of capacitive or inductive reactive power while operating at 10 MW. The reactive power is also continuously variable and controllable with a voltage regulator. *The extra 1 MVA of converter capacity thus provides the same dynamic range as a 9.2 Mvar SVS.* Because most SVSs provide primarily capacitive reactive power, a 4.6 Mvar capacitor is required to make the converter fully comparable to an SVS. However, even with the cost of the capacitor, and recognizing that GTO based converters are more costly (per MVA) than thyristor based SVS, the battery converter is a very economical alternative to SVS capacity.

To maintain proper voltage level SDG&E is presently planning to add either 600 Mvar of capacitors at the transmission voltage level of 69 kV and above, or 400 Mvar of capacitors at the 12 kV distribution level by the year 2000. Transmission planning indicates that probably SDG&E will add the capacitors at the 12 kV level as this alternative is more economical. SDG&E is considering the addition of SVS as well as conventional fixed and switched capacitors, although there is no specific quantity of SVS planned.

SDG&E has estimated that installed cost for new conventional capacitor banks installed at the transmission voltage level will be $30/kvar.[2] SVS is estimated to cost three times as much or about $90/kvar. Both numbers are reasonable, though some utilities are finding actual costs of conventional capacitor banks to be up to 50% higher where land costs are high. The $90/kvar number for SVS is for relatively large SVS (above 100 MVAR). Costs can be much higher where space or system requirements dictate SVS sizes under 100 MVAR.

A 10 MW battery is likely to have a converter cost of about $150/kVA. Assuming that the *incremental* cost of converter capacity is 2/3 of this overall $/kVA cost, an incremental kVA would cost about $100. As described above, adding an additional MVA of converter capacity will provide 4.6 Mvar of capacitive reactive power (more at reduced MW output) at a cost of about $100,000. The cost of 4,600 kvar from a 10 MW battery converter is thus about $22 per kvar. The battery converter thus appears economically competitive ($8 kvar savings) with switched shunt capacitors installed at the transmission level on the SDG&E system.

2. Though this is a typical cost figure, some utilities are finding transmission capacitor banks to be up to 50% higher than this because of land costs.

Hence a 10 MW battery could eliminate 4.6 Mvar of capacitors at a PWRR savings of $51,869 if conventional shunt capacitors were displaced. The dynamic capability and equal inductive range would be a bonus, and may have a large value if batteries are compared against SVS, which may cost $90/kvar or more.

A 10 MW battery needs 4.6 Mvar of switched shunt capacitors to be equivalent to 9.2 Mvar of SVS capacity. At $30/kvar for 4.6 Mvar of capacitors, and $22/kvar for the other 4.6 Mvar, 9.2 Mvar of dynamic range is available for $25/kvar, less than 1/3 the cost of conventional SVS capacity (from a large SVS). If SVS were displaced a PWRR savings of $880,000 would occur from each 10 MW battery. On a capital investment basis, these example PWRR benefits translate into battery storage credits of $4/kW and $62/kW for shunt capacitors and SVS displacement respectively.

Figure 3-2 presents additional information on the economics of reactive power and voltage control. This example in the figure is for a 10 MW battery and a converter in the range 10 MVA to 15 MVA. The figure shows the reactive power that is available when the battery is not charging or discharging, and the reactive power that is available when the battery is operating at its full power rating. Only the capacitive (or inductive) portion is shown. Total kvar range from capacitive to inductive would be twice the numbers shown. The dollar per kvar curve is based on an assumed incremental battery converter cost of $125 per kva and just the capacitive kvar supplied by the converter. The dollar per kvar amount in terms of SVS capacity would be half that shown (because total kvar would be doubled).

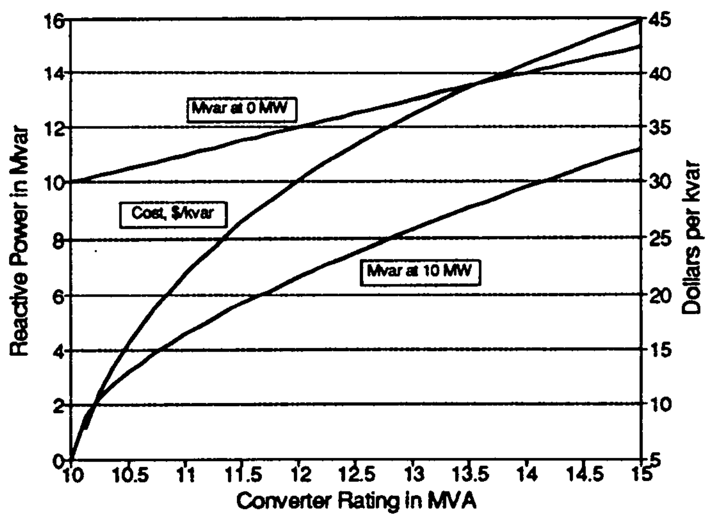

Figure 3-2. Reactive Power Can Be Economically Provided By Increasing the Size of the Battery System Power Converter

The reactive power from a GTO based power converter could be controlled in several ways. One would be to have operators at the system or distribution control center set kvar output. The controller on the battery system would hold the scheduled kvar level regardless of system voltage. Operators could use the battery kvar as needed for local power factor correction or to improve voltage in the upstream subtransmission system. Another would be to provide the converter with a voltage regulator. Kilovars would be produced as needed, up to the converter capability, to hold the desired voltage. The voltage regulator could control substation primary or secondary voltage. It might be connected to control primary voltage to help ensure good voltage levels and voltage stability in the subtransmission system. It could do this even though it is connected to the substation secondary bus. In this mode of operation the substation LTC would continue to regulate secondary voltage. If set to control secondary voltage, the converter control would be coordinated with the substation LTC transformer control so that the LTC would move only when the converter reactive power is insufficient to hold substation secondary voltage.

OTHER POTENTIAL BATTERY STORAGE T&D BENEFITS

Voltage Stability or Voltage Collapse

Discussion with SDG&E engineers indicates that voltage instability or voltage collapse problems are not presently being experienced and are not anticipated in the future on the SDG&E system. There are three reasons for this. First there is a significant amount of local generation in and near the SDG&E service territory. The second reason is SDG&E's practice of controlling distribution voltages with capacitors to provide power factor correction to near unity power factor at distribution substations. Third, SDG&E maintains a transmission system minimum voltage criteria of 0.9 or higher.

At this time the ability of batteries to provide rapid dynamic voltage control like an SVS does not appear to be needed by SDG&E. However, SDG&E planners are studying potential future applications of SVS on the SDG&E system, possibly in the late 1990s, as the system load grows. Batteries are a potentially cost effective alternative to SVS in solving future voltage control problems requiring SVS, because batteries can improve voltage stability in two ways. They can supply real power near loads thus reducing the loading on a stressed or weakened system. They can also provide reactive power and regulate voltage at about $22/kvar versus $90/kvar as discussed in the previous two sections.

Damping and First Swing Stability

Damping and first swing stability problems were not identified as potential SDG&E transmission system expansion problems during discussions with SDG&E engineers. Hence, no battery storage stability benefits were identified as part of this study. However, damping and first swing stability problems are a concern in determining power transfer limits into the Southern California region. Previous experience indicates that batteries can provide a significant amount of damping and improve first swing stability limits if batteries are located near the "receiving end" of a transmission system; and provision is made to modulate battery storage MW output in the millisecond time frame. If SDG&E installs batteries on their system, the batteries will be located at the receiving end of this regional transmission system for power imports from Arizona and the Northwest. Hence, in the future, additional damping and first swing stability economic benefits may be identified for future SDG&E batteries, based on increased regional power transfer capability.

OTHER CONSIDERATIONS AND ISSUES

Previous sections of this report show there are significant potential economic benefits associated with the installation of batteries to defer new facilities on heavily loaded SDG&E T&D systems. However, obtaining these potential battery storage benefits may require changes in present SDG&E T&D planning practices which do not include battery storage characteristics.

Reliability

The first issue is reliability. Present SDG&E *transmission* planing criteria is deterministic, and has been developed over the years to address the outage frequency and duration characteristics of transmission equipment. SDG&E *distribution* planning criteria includes consideration of customer outage frequency and duration.

Future batteries and power conversion systems should provide the reliability level that HVDC lines, SVSs, and adjustable speed drives do today. Hence battery storage component failures should cause just a few battery outage events per year, and outage duration should be just a few days or less per year. In this regard batteries will rival transmission lines and distribution lines, but may not compete with transformers.

However, beyond providing reliability similar to transmission and distribution lines, batteries may have an additional reliability advantage. A battery is a 'local source' and thus is not dependent on upstream components as is, for instance, the substation transformer. The battery is, in effect, an independent source of power and thus may make a more significant contribution to reliability than its outage rate and duration statistics would seem to indicate. It is an independent source because it is not part of a series string of devices, any one of which can cause an outage or reduce capacity.

However, unlike transformers and transmission and distribution lines, batteries are not necessarily "available" just because they are on-line. Batteries thus may need to be in a charged state, and have a specific energy storage capability to be considered reliable backup to various T&D facilities. On the other hand, a battery that is normally discharged to 20% of capacity but can be discharged to 90 or 100% in an emergency may provide reliability by supplying energy for the time needed for switching actions to restore or re-structure lines and transformers to carry the full substation load.

A probabilistic reliability assessment may be needed to fully recognize a battery's contribution to reliability. Utilities still depend heavily on deterministic criteria, and thus may have difficulty measuring the reliability of a substation load served in part from a battery. The contribution a battery can make in meeting utility distribution reliability criteria has not, to our knowledge, been analyzed.

Short-Term Transformer Loadings

The second issue is short-term transformer loadings. Existing SDG&E allowable short-term transformer loadings are significantly above normal MVA ratings. These short-term ratings are based on appropriate assumptions about the thermal impact of the typical transformer loading cycle. The thermal time constant of the massive transformer allows significant overloading without significant loss of life if the period of heavy loading is balanced by a previous period of light loading. The typical substation load cycle provides the alternating light and heavy loading that makes transformer overloading practical.

The charging of batteries during off-peak periods will increase off-peak transformer loading, but discharging them will reduce the on-peak loading. Because on-peak transformer losses are higher than off-peak losses, the flatter loading curve will reduce transformer losses overall, and thus reduce transformer heating. This will *increase* the average power a transformer can handle. Hence at the same time a battery can defer transformer capacity and increase the load that can be placed on existing transformers. This benefit has not been quantified and would require analysis that has not been done.

Land Use

The third issue is land use. Sections 2 and 3 presented land use requirements and costs for T&D facilities. Judicious placement of batteries in the SDG&E T&D system to defer new T&D facilities also requires space. This space will be required in high land cost areas, especially for batteries placed within the urban San Diego area. Discussions with SDG&E engineers indicate that there may be problems obtaining space in some locations, and discussions with SDG&E land purchase personnel indicate that the land cost will be high. These factors must be considered as part of the application of batteries in the SDG&E T&D system.

Review of recent modular battery storage designs indicate that a 500 kWh battery storage system with dimensions of 26′ long by 9′ wide by 12′ high may soon be commercially available. Preliminary layout of these modules assuming 5′ spacing indicates combination of several modules require about 1250 ft^2 per MWh. At \$20/ft^2 land cost this results in a battery storage land use cost of about \$25,000 per MWh of battery storage installed.

4

POTENTIAL DISTRIBUTION SYSTEM BENEFITS

NEW DISTRIBUTION PROJECTS

In general, the purpose of the distribution system is to reliably distribute power within load centers. Since the SDG&E distribution system, like that of other utilities, consists of many distribution circuits delivering small amounts of power, new distribution projects are planned, designed, and installed regularly by SDG&E. SDG&E plans and designs these circuits in accordance with its distribution design standards.[1] These SDG&E standard designs are used for developing appropriate new distribution project characteristics considered in this study.

Some or all of 20 MW of batteries in the transmission example presented in Section 2 could provide transmission benefits while located at the 12 kV bus of the 69/12 kV distribution substation. Or, since batteries are modular, some of the batteries could be distributed out in the 12 kV distribution system in several smaller battery installations, probably in the range 1 MW to 5 MW. Siting batteries in the distribution system can affect distribution system reliability and power flow, resulting in potential distribution system benefits.

In this study, potential benefits of 1 to 5 MW battery applications are considered. Therefore, potential distribution system benefits associated with the judicious siting of batteries are confined to 69/12 kV (or 138/12 kV) distribution substations and 12 kV primary distribution feeders.

A standard SDG&E 100 MVA 69/12 kV distribution substation design consists of 4-28 MVA transformers. Generic new distribution substation projects are considered, including deferring the addition of a 28 MVA transformer to an existing substation and deferring the construction of a new substation containing a single 28 MVA transformer.

Standard SDG&E 12 kV distribution feeder capacity is 9 to 10 MVA and typical feeder lengths are 5 to 10 miles. This study considers deferring the addition of a 5 mile 9 to 10 MVA distribution feeder.

1. Electric Distribution Design Manual, San Diego Gas and Electric, effective 1/1/91 to 12/31/91.

DISTRIBUTION SYSTEM RELIABILITY CRITERIA

Distribution system reliability criteria are defined in detail in the SDG&E Distribution Design Manual. In particular, regarding overload capacity, 28 MVA transformers are allowed to be routinely loaded to 30 MVA during summer peak loading conditions. After a transformer failure during summer conditions, substation loading must be reduced to 38 MVA in 15 minutes and to 32 MVA in 4 hours for a two transformer substation; to 76 MVA in 15 minutes and to 70 MVA in 4 hours for a three transformer substation; to 110 MVA in 15 minutes and to 104 MVA in 4 hours for a four transformer substation. Allowable transformer loadings are increased during winter conditions.

At SDG&E, distribution feeders are generally radial with normally open ties to other distribution circuits to provide backup. Feeders can be broken into sections by opening line switches and other tie switches closed to shift load to other feeders or reach customers beyond faulted feeder sections. The number of feeders and requirements for new feeders are determined on a case by case basis from customer outage frequency and duration calculations, voltage spread limits, and substation and feeder MVA capacity.

Allowable voltage spread is 114 to 120 v at the customer service points throughout the distribution system. This requires consideration of both distribution primary and secondary system voltage drops during both peak and light loading conditions. Other SDG&E voltage policy includes the addition of shunt capacitors in the distribution system to maintain a power factor of 0.995 at the distribution substation.

POTENTIAL DISTRIBUTION SUBSTATION TRANSFORMER DEFERRAL BENEFITS

Typical SDG&E distribution substation transformer installed cost assumptions are presented in Table 4-1. Adding a new 28 MVA transformer may cost anywhere from $700,000 to $8 million dollars depending on the site-specific circumstances. As with transmission expansion described in Section 2, a large component of this cost is land. The standard area requirement for a 100 MVA distribution substation is 450′ x 550′ (5.6 acres). Assuming a high land cost of $\$20/ft^2$, this translates into $4,950,000. At $\$25/ft^2$ land costs for a 100 MVA distribution substation can exceed $6,000,000.

Table 4-1
TYPICAL RANGE SDG&E DISTRIBUTION SUBSTATION TRANSFORMER COST

Transformer Addition	1990 Dollar Installed Cost ($1000)
Add 28 MVA Transformer to Existing Substation	700-2,000
Add 28 MVA Transformer at New Substation	2,000-8,000

To put these costs in perspective, consider the potential distribution substation transformer deferral benefit at an existing two-transformer substation loaded to 60 MW and approaching its capacity limit. Assuming a load growth of 3%, a third 28 MVA transformer addition costing about $2 million may be able to be deferred about 3 years by adding a battery which can reliably supply about 5 MW at the 12 kV bus during the annual peak load. Assuming a 16.35% fixed charge rate, the potential battery storage benefit to defer the third transformer totals $981,000 or $327,000 per year for three years. Assuming a discount rate of 11.6% and 4% inflation, the resulting transformer deferral PWRR savings benefit associated with deferring the third transformer three years is $538,000.

In a substation with a lower growth rate, for instance, 1.5%, the same 5 MW battery would defer the transformer 6 years. In this case the potential battery storage benefit totals $1,962,000 or $327,000 per year for six years. The resulting transformer deferral PWRR savings benefit associated with deferring the third transformer six years is $973,000.

On a capital investment basis, this example transformer deferral benefit translates into a battery storage credit of $76/kW benefit for the 5 MW battery if the transformer is deferred 3 years, and $138/kW if it is deferred six years.

Consider a larger four-transformer distribution substation approaching capacity at 120 MW and a 3% load growth assumption. Adding a battery which can reliably supply 10 MW at the 12 kV bus during annual peak load may allow deferral of a 28 MVA transformer and a new distribution substation site for a period of 3 years. If the new transformer addition costs $8 million and the fixed charge rate is 16.35%, the potential battery storage benefit for deferring this new transformer addition totals $3,924,000 or $1,308,000 per year for three years. Again assuming a discount rate of 11.6% and 4% inflation, the resulting transformer deferral PWRR savings benefit associated with deferring the new transformer three years is $1,408,000.

On a capital investment basis, this example transformer deferral benefit translates into a battery storage credit of $100/kW for the 10 MW battery.

Deferring the new substation six years for a 1.5% growth rate case would give the 10 MW battery a PWRR savings benefit of $3,891,000 and a battery energy storage credit of $276/kW.

POTENTIAL 12 KV FEEDER DEFERRAL BENEFITS

Typical SDG&E 12 kV feeder cost assumptions are presented in Table 4-2. Typical 12 kV feeder costs vary from about $250,000 per mile to $800,000 per mile.

For this study, potential benefits associated with deferring a generic 5 mile underground feeder addition (with conduit) will be evaluated. This new 12 kV feeder will be assumed to be installed within the city of San Diego franchise area where <u>no ROW purchase</u> is required.

Table 4-2
TYPICAL SDG&E 12 kV FEEDER COSTS

12 kV Feeder Construction Type	1990 Dollar Installed Cost* ($1000/mi)
Overhead Construction	250
Underground, With Conduit	800
Underground, Existing Conduit	250

* Without Land Cost

The generic 5 mile, 12 kV feeder is expected to cost about $4,000,000. For this study, assume that a judiciously placed reliable 2 MW battery within the distribution system can defer this new feeder addition 3 years. (Note that future site specific distribution studies meeting SDG&E reliability criteria will be required to determine potential feeder deferral benefits on a case by case basis.) Assuming a 16.35% fixed charge rate, the potential battery storage benefit associated with deferring the feeder totals $1,962,000 or $654,000 per year for three years. Assuming a discount rate of 11.6% and a 4% inflation rate, the resulting feeder deferral PWRR savings benefit is $704,000.

On a capital investment basis, this 5 mile, 12 kV feeder deferral benefit translates into a battery storage credit of $250/kW for the 2 MW battery. Note that the potential battery storage credit would be significantly higher if ROW costs were required for the 12 kV feeder addition.

LOSS REDUCTION

The loss reduction consideration and issues described in Section 3 for transmission also apply to distribution systems. However, the important issues concerning loss reduction considerations on distribution systems are slightly different.

First, on distribution systems, the location of the generation used to charge the batteries and the location of the generation displaced when the batteries are discharged is not expected to have a significant impact on the relative magnitude of the losses and the resulting relative cost of losses.

Second, it is likely that the daily load shape characteristics of individual feeders may vary significantly from the coincident daily native SDG&E system load shape.

Appendix B presents plots of composite daily load curves for commercial and residential substation loads plus example summer and winter daily load shape plots for one of SDG&E's distribution substations. These distribution substation daily load shapes vary significantly from the total native system load shapes in Section 2 as measured at SDG&E generating units and tie lines. And individual feeders connected to this substation are also expected to have different daily load shapes. These plots verify the second issue raised above.

VOLTAGE REGULATION

The voltage regulation consideration and issues described in Section 3 for transmission also apply to distribution systems. Table 4-3 presents SDG&E cost estimates for conventional capacitor banks installed at the 12 kV distribution level. Overhead capacitors cost about $12.50 per kvar and pad mounted capacitors cost $25 per kvar.

Table 4-3
SDG&E SHUNT CAPACITOR COST ESTIMATE

Capacitor Type	Installed Cost $
1200 kvar, Overhead	15,000
12000 kvar, Pad Mounted	30,000

As described in Section 2 batteries are expected to provide capacitance at about $22 per kvar. Thus batteries appear to be economically competitive with pad mounted conventional shunt capacitors installed on the 12 kV distribution system, and batteries are significantly more economical if their presence avoids the need for SVS capacity (Batteries in the SDG&E distribution system will displace SVS capacity in the SDG&E transmission system because SDG&E does not apply automatic LTCs in its distribution substation).

OTHER BATTERY STORAGE T&D BENEFITS, CONSIDERATIONS AND ISSUES

The last two subsections of Section 3 (transmission) dealt with related issues such as voltage stability, T&D system reliability, and land use. These issues are common to transmission and distribution; most of the material from these two subsections of Section 3 applies equally to distribution.

5

COST/BENEFIT ANALYSIS

In this section the dollar value of the benefits described in the previous three sections is compared to the cost of installing batteries. Following common industry practice, costs and benefits are expressed in 1990 dollars per kilowatt of capacity or dollars per kilowatt-year of capacity; the latter is a current dollar levelized cost over the battery unit's life.

BATTERY CAPITAL COSTS

Because there are currently only a handful of utility battery installations in operation or planned, there are no commonly accepted estimates for battery storage system costs. In addition, costs are very dependent not only on power capacity and storage capacity, but also on frequency with which the battery is to be charged and discharged and the depth of discharge.

The cost estimates used here are from EPRI's Technical Assessment Guide (TAG). They have already been described in Section 1 of this document. Adjusted for inflation, the total cost is $703/kW for a 3-hour battery and $943/kW for a 5-hour battery, including land cost. The TAG does not provide a cost estimate for a one-half or 1-hour battery that could provide spinning reserve but would have minimal energy capacity; we estimate that such a battery would cost $350/kW. This is based on the EPRI TAG numbers, but reducing the storage component of the 3-hour battery cost by two-thirds.

Using a fixed charge rate of 16.35%, as suggested by SDG&E, to convert overnight capital costs to current dollar levelized annual battery costs yields the following:

Size (hours)	Levelized Capital Cost ($/kW-year)
1	$57.20
3	$114.94

The cost estimates in the EPRI TAG do not include cell replacement during the life of the battery system; the individual cells do not last as long as the entire system. Depending on the number of cycles per year that the battery is operated, cell replacement costs could add on the order of $100/kW to the battery cost, or about $15/kW-year. In addition, the operating and maintenance

(O&M) costs for the battery system should be included in a detailed analysis; they are ignored in this screening-level analysis.

CAPACITY VALUE OF BATTERY

Another potential benefit or savings that can be attributed to batteries, but not discussed in the previous sections, results from its contribution to total system generating capacity. If the addition of batteries allowed SDG&E to reduce new combustion turbine purchases or purchase less firm capacity, then a capacity credit on the order of $40 to $75/kW-year[1] would be appropriate. SDG&E is planning additions to generating capacity during the next decade, so such a capacity credit appears warranted.

COMPARING BENEFITS TO COSTS

The annual costs just described can now be compared to the benefits estimated in Sections 2, 3, and 4. Recall that, as described in Section 2, there were no load-leveling benefits on the SDG&E system. This resulted from the relative flatness of the hourly system marginal costs (system lambda).

Two operating modes or applications were considered for calculating dynamic operating benefits: a three-hour battery operated in a daily charge/discharge mode, and a battery with much smaller storage capacity used only to provide spinning reserve. In order to maximize the net operating benefits, enough battery capacity must be added to allow the decommitment of one of the marginal units; this could require about 100 MW of battery capacity. The net operating benefits were greater when the battery is used to provide spinning reserve; in this case, they were calculated to be $26.89/kW-year. However, a battery with only minimal storage capacity might not be able to provide all of the T&D benefits described in Sections 3 and 4, especially deferral of T&D investments. The three-hour battery provided net operating benefits of $23.23/kW-year when operated in charge/discharge mode.

It is necessary to account for the fact that the net operating benefits, which were calculated only for 1990-1991, will escalate over time with inflation and with increasing natural gas prices. For inflation of 4 percent per year and real escalation of natural gas prices of 1.5 percent per year, the effect is to roughly double the 1990-1991 value to yield net operating benefits of about $50/kW-year levelized in current dollars. This is a conservative estimate that could be higher in the future as load growth forces increasing utilization of less economic units.

T&D investment deferral benefits range as high as $1200 per kW, depending on the investment deferred; the $1200 figure is admittedly extreme. Different hours of storage capacity will likely be required for different T&D applications; in particular, the $1200/kW benefit is

1. Combustion turbine cost of $400/kW times levelized fixed charge rate of 16.35% = $65/kW-year. Life extension and capacity purchases will probably cost less; combined cycles will cost more.

associated with deferral of a 69KV transmission line and would require more storage capacity, which would be more expensive. Using the same levelized fixed charge rate used above for levelizing battery capital costs, and assuming that the battery would be sited to capture at least moderate T&D benefits, yields a T&D value of $10 to $200 per kW of battery capacity per year.

Benefits in all categories are summarized in Table 5-1. In a screening level analysis such as this, it is not possible to be more precise. The T&D benefits in particular are very site-specific and can not be precisely calculated without identifying sites for battery installations and then carrying out detailed T&D expansion plans with and without batteries.

Table 5-1
BENEFITS SUMMARY FOR SDG&E SYSTEM

Category	Annual Benefit ($/kW-year)
Capacity	40-75
Generation	50-75
T&D	10-200
Environmental	1-20*
TOTAL	100-370

*For charging with on-system units.

Comparing total benefits to the battery costs, which are roughly $60 to $130 per kW-year depending on the number of hours of storage indicates that batteries may be quite economic on the SDG&E system.

6

CONCLUSIONS AND RECOMMENDATIONS

In this study several types of benefits that would occur from the addition of batteries to the SDG&E system were calculated: generation (load-leveling, dynamic operating, and environmental) and transmission and distribution. These benefits were also compared to the costs of adding batteries. The results suggest that savings in dynamic operating costs and T&D costs may justify the addition of batteries to the system.

GENERATION BENEFITS

Generation benefits were calculated for eight days during 1990-1991, one weekday and one weekend day for each season, using actual SDG&E data. The benefits were calculated for five gas-fired steam turbine units whose operation is most likely to be affected by the addition of batteries to the system. Two modes of battery operation were considered: daily charge/discharge with a three-hour battery, and provision of spinning reserve only with a one-hour battery.

Load-Leveling Benefits

Because the marginal units on the SDG&E system are typically gas-fired steam turbines for all hours (usually the Encina and South Bay units), the system marginal energy costs do not differ much between on-peak and off-peak hours. Coupled with the assumed battery efficiency of around 80 percent, this means that no load-leveling savings could be achieved on the SDG&E system.

Dynamic Operating Benefits

A large portion of the operating costs of power plants results from fluctuating loads. These costs are called dynamic operating costs, and include such things as startups, minimum loading, load following, and ramping. Technologies such as batteries that can reduce these costs are said to provide dynamic operating benefits.

For each of the eight days the potential reduction in load following, minimum loading, startup, and spinning reserve costs was calculated for each of the five units. The most cost-effective unit for decommitment was identified on each day. By accounting for the relative occurrence of each of the eight "day types" during the year, an annual savings was calculated. For the 1990-1991 period, the savings was about $23-26 per kilowatt per year of battery capacity; the biggest component of the savings is from reductions in load-following costs. That is, each kilowatt of battery capacity would reduce system operating costs 23 to 26 dollars. Accounting for inflation and increases in natural gas prices, this is equivalent to an annual savings of about $50, levelized in current dollars, per kilowatt per year. The savings are likely to increase in the future as load growth forces increasing utilization of less economic units.

Environmental Benefits

Storage in general, and batteries in particular, have the potential to shift the type and location of emissions of NO_x, SO_x, and CO_2; NO_x is of greatest concern in Southern California at this time. Even if providing only spinning reserve, batteries have the potential to reduce NO_x emissions by allowing the system to be operated more efficiently. The addition of batteries to the system might also make it unnecessary to retrofit expensive pollution controls such as SCR to an existing gas-fired unit, if that unit's operation would be sharply reduced as a result of adding batteries.

TRANSMISSION AND DISTRIBUTION BENEFITS

This project identified the potential role battery storage could play in providing equal or better performance than other transmission and distribution (T&D) options, such as adding new T&D facilities and equipment. Current SDG&E transmission and distribution facility expansion study results and transmission and distribution system design practices were reviewed with appropriate SDG&E personnel to identify anticipated and potentially needed transmission additions.

The results of this initial study indicate that strategically installing battery storage on the SDG&E system may result in large T&D system benefits—up to $1200/kW. The actual magnitude of the site specific T&D benefits and corresponding battery storage requirements should be determined on a case-by-case basis from more detailed analysis. Further analysis should include the development of load profiles for substations that are candidate battery sites so that the number of hours of storage required for equipment deferral can be determined.

Table 6-1 presents a summary of the range of annual potential savings to SDG&E associated with the deferral of various new transmission and distribution facilities. Table 6-2 presents a summary of the magnitude of potential benefits and associated battery storage credits associated with T&D application of batteries on the SDG&E system. Several applications have storage credits in the range of several hundred dollars of battery capacity per kilowatt; for a specific 69 kV transmission line the credit exceeds $1,000 per kilowatt.

Table 6-1
RANGE OF POTENTIAL ANNUAL T&D SAVINGS TO SDG&E

New T&D Project	Range of Annual Savings ($1000/yr)
Defer Proposed 1994 69 kV Project	654 – 1,635
Defer 15 mi. 69 kV Line	591 – 8,361
Defer 15 mi. 230 kV Line	3,163 – 16,356
Defer 230/69 kV Transformer Existing Sub	1,039 – 1,116
Defer 69/12 kV Transformer Existing Sub	114 – 327
Defer 69/12 kV Transformer New Sub	327 – 1,308
Defer 5 mi. 12 kV Underground Feeder	654
Defer 4.6 MVAR of Shunt Capacitors	6
Defer 9.2 MVAR of SVS	102

Table 6-2
EXAMPLE T&D BATTERY T&D BENEFITS AT SDG&E

Battery Application	Battery Size (MW)	PWRR Savings ($1000)	Battery Credit ($/kW)
1. Defer 15 mi. 69 kV Line 9 years			
Single Circuit	20	31,057	1100
Double Circuit	20	33,874	1200
2. Defer 28 MVA 69/12 kV Transformer 3 years			
Existing Sub	5	538	76
New Sub	10	1,408	100
Defer 28 MVA 69/12 kV Transformer 6 years			
Existing Sub	5	973	138
New Sub	10	3,891	276
3. Defer 5 mi. 12 kV Feeder			
3 years	2	704	250
4. Defer 4.6 MVAR of Capacitors to Perpetuity			
Shunt Capacitors	10	47	4
SVS	10	880	62

COST/BENEFIT ANALYSIS

Summing the capacity, generation, environmental, and T&D benefits yields levelized current-dollar savings of $100 to 370/kW-year, compared to a levelized current-dollar cost of $60 to $130/kW-year. These values suggest that batteries would be a cost-effective addition to the SDG&E system.

Some benefits may be mutually exclusive. This is true both for different T&D benefits and for T&D benefits versus dynamic operating benefits. For example, the load-leveling that batteries make possible can reduce T&D losses, but this benefit may be lost if investment is deferred as a result of adding batteries. The interactions between the various benefits, i.e., whether they are additive or mutually exclusive, depends on storage size, location, system load shapes, load shapes at individual substations and on individual transmission and distribution lines, how the system (including the battery) is operated, and on any equipment deferred as a result of adding batteries.

RECOMMENDATIONS

Based on the results of this screening-level study, it is recommended that SDG&E seriously consider the addition of battery storage to its system. A detailed study to verify the findings of this initial screening study and to calculate the benefits more precisely is recommended. Such a study should include the following aspects:

1. More detailed calculation of generation dynamic operating costs and benefits should be carried out, including examination of multiple weeks of system operation during the course of the year and consideration of how system operation, and especially the operation of marginal units, is likely to change in the future.

2. Detailed T&D expansion studies should be carried out, with and without batteries. Potential sites for installing batteries should be identified.

3. Particular care should be paid to the interactions among the various benefits, to ensure that batteries are not being justified on the basis of benefits that may be mutually exclusive.

4. Comparative evaluation of the economics of battery storage with other capacity additions under consideration by SDG&E.

Such detailed study would also allow a better assessment of the "optimum" battery size and the best time for adding the battery plant to the SDG&E system.

A

TRANSMISSION FACILITY ASSUMPTIONS

Appendix A contains a listing of the detailed assumptions supplied by SDG&E transmission planning personnel for use in this analysis. Table A-1 presents a listing of typical transmission line construction cost estimates for alternative overhead and underground transmission line construction types and phase conductor sizes. Table A-2 presents a listing of appropriate line ratings and impedance data for the various transmission construction types. Table A-3 presents typical bulk power transformer plus breaker installed cost estimates used for current SDG&E transmission planning studies.

Table A-1
TYPICAL TRANSMISSION LINE CONSTRUCTION COST ESTIMATES

Construction Type	1990 Dollar Installed Cost* ($1000/mile)
1. 69 kV Wood Poles:	
Single circuit 336.4 ASCR/AW	$139
Single circuit 636 ACSR/AW	162
Single circuit 1033.5 ASCR/AW	178
Twin circuit single conductor 1033.5 ASCR/AW	320
Single circuit overbuild 1033 ASCR/AW w/4W636 12 kV	353
Single circuit re-conductor (1/0 cu. - 336 al.)	148
Single circuit re-conductor (1/0 cu. - 636 al.)	162
Single circuit re-conductor (1/0 cu. - 1033 al.)	178
Single circuit re-conductor (4/0 cu. - 636 al.)	154
Single circuit re-conductor (4/0 cu. - 1033 al.)	146
2. 138 kV Wood Poles:	
Single circuit single conductor 1033.5 ACSR/AW	$170
3. Wood H-Frame Structures (1033.5 ACSR/AW):	
138 kV single circuit bundled conductor	344
230 kV single circuit bundled conductor	369
4. 230 kV Lattice Tower (1033.5 ACSR/AW):	
Single circuit single conductor	565
Single circuit bundled conductor	664
Twin circuit single conductor	693
Twin circuit bundled conductor	889
5. 230 kV Steel Poles (1033.5 ACSR/AW):	
Single circuit single conductor	841
Twin circuit single conductor	964
Twin circuit bundled conductor	1,158
Bundle existing single circuit 1033.5 on steel structures	100
Add single circuit single conductor 1033.5 to steel structures	132
Add single circuit bundled conductor 1033.5 to steel structures	231
6. 500 kV Lattice Towers (2156 ACSR/AW):	
Single circuit, bundled conductor	556
7. 69 kV Underground:	
Install 1750 MCM A1 cable direct buried in an existing open trench	549
Install 1750 MCM A1 cable in existing ducts	567
Trench for direct buried cable	689
Trench for direct buried cable w/4" duct for telecommunication	757
Installation twin circuit duct bank (trench and substructures only)	1,396
Install twin circuit duct bank w/4" duct for telecommunication (trench and substructures only)	1,419

* Estimates include AFDC, interest, local engineering, engineering support, P&W, and 15% contingency.

Table A-2
APPROXIMATE LINE RATINGS AND IMPEDANCE DATA
69, 138, 230 & 500 kV

Voltage/ Conductor	Size		Max. (1) Ampacity	(2) MVA	(2) R(pu)	(2)(3) X (pu)	b/2(pu)
69kV							
Single	1/0	Cu	270	32	.012750	.016770	.0001284
Single	4/0	Cu	421	50	.006360	.016060	.0001364
Bundled	4/0	Cu	842	101	.003180	.011200	.0001865
Single	1/0	ACSR	269	32	.023520	.018480	.0001350
Single	336	ACSR	571	68	.006440	.014050	.0001510
Bundled	336	ACSR	1142	136	.003220	.010500	.0002000
Single	636	ACSR	854	102	.003400	.013250	.0001605
Bundled	636	ACSR	1708	204	.001700	.009870	.0002130
Single	1033	ACSR	1145	137	.002180	.013600	.0001570
1750 MCM	A1	Cable	(4)	(4)	.001440	.007183	.0039600
138 kV							
Single	636	ACSR	854	204	.000886	.003810	.0004500
Bundled	636	ACSR	1708	408	.000424	.002760	.0007550
Single	1033	ACSR	1145	274	.000542	.003960	.0005350
Bundled	1033	ACSR	2290	547	.000271	.002920	.0007150
Bundled	1590	ACSR	3006	719	.000179	.002740	.0007625
230 kV							
Single	1033	ACSR	1145	456	.000196	.001425	.0014850
Bundled	1033	ACSR	2290	912	.000098	.001045	.0020250
Single	1590	ACSR	1503	599	.000130	.001380	.0015400
Bundled	1590	ACSR	3006	1198	.000342	.001010	.0020750
500 kV							
Bundled	2156	ACSR (5)	(6)	(6)	.000110	.000238	.0088000

(1) Max. Ampacity at Ambient Temperature = 100°, and a maximum conductor temperature of 2 FPS wind of 167° for Copper and 194° for Aluminum. (Temperatures are assumed to be degrees Fahrenheit).
(2) On 100 MVA base.
(3) Total 3 phase line-charge.
(4) Varies, dependent on manufacturer and design configurations.
(5) Base on no series compensation; degrees=40.5; phase-space=32.
(6) Not provided

Table A-3
BULK POWER TRANSFORMER AND BREAKER COST ESTIMATES

		1990 Dollar Installed Cost ($1000)
1. Transformer, 2 High Side Breakers, 1 Low Side Breaker		
500/230 kV	1000 MVA	11,119
230/138 kV	392 MVA	7,612
230/69 kV	224 MVA	6,354
2. Transformer, 2 High Side Breakers, 2 Low Side Breakers		
500/230 kV	1000 MVA	13,988
230/138 kV	392 MVA	8,084
230/69 kV	224 MVA	6,826

B

DAILY SDG&E SYSTEM LOAD SHAPES AND MARGINAL GENERATION COSTS

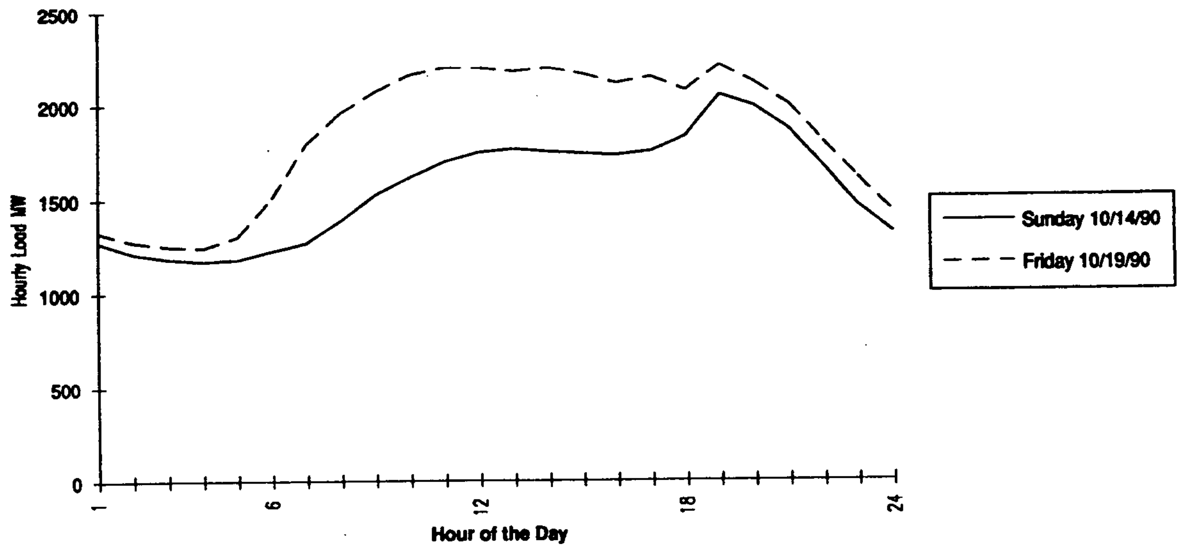

Figure B-1. Native Daily Load Shapes—Fall 1990

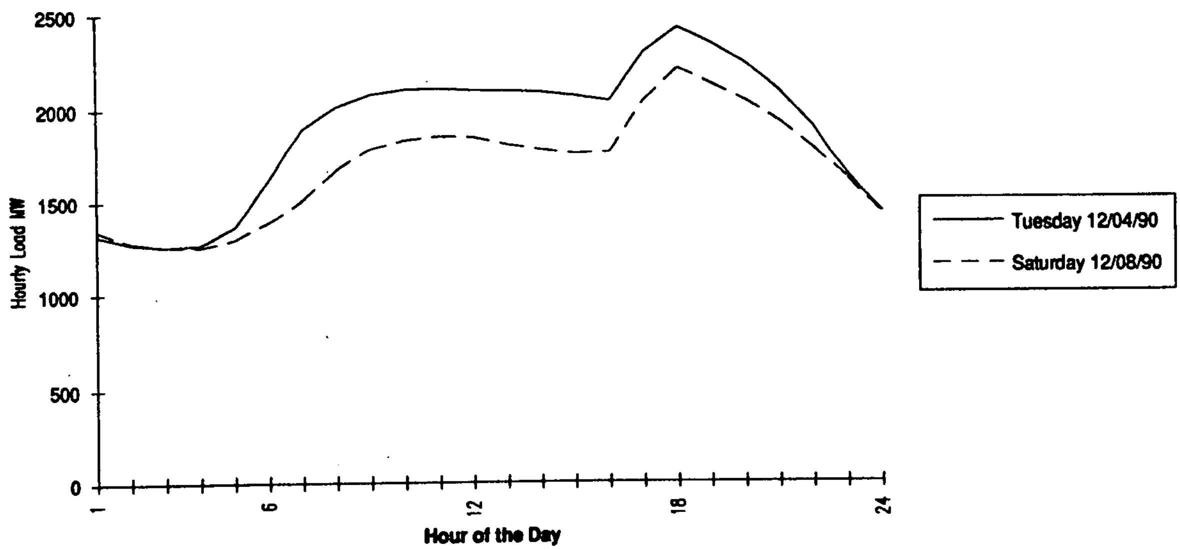

Figure B-2. Native Daily Load Shapes—Winter 1990

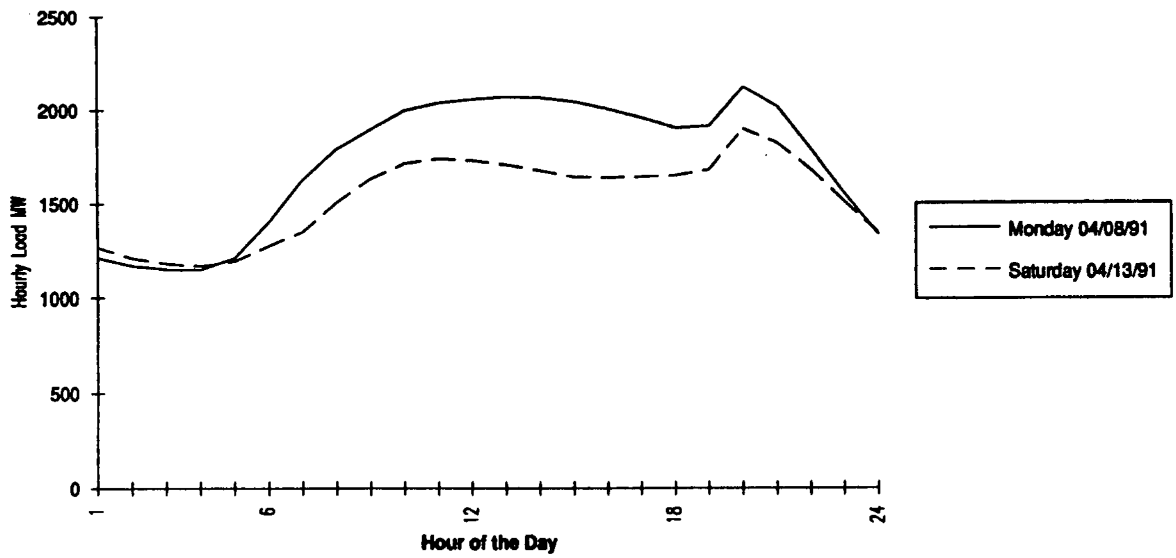

Figure B-3. Native Daily Load Shapes—Spring 1991

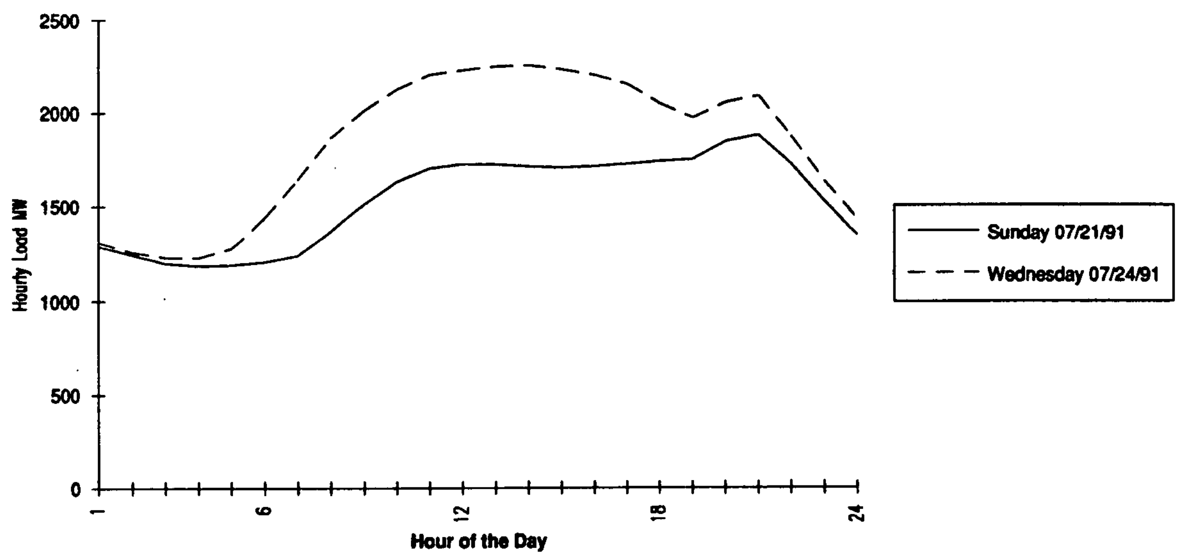

Figure B-4. Native Daily Load Shapes—Summer 1991

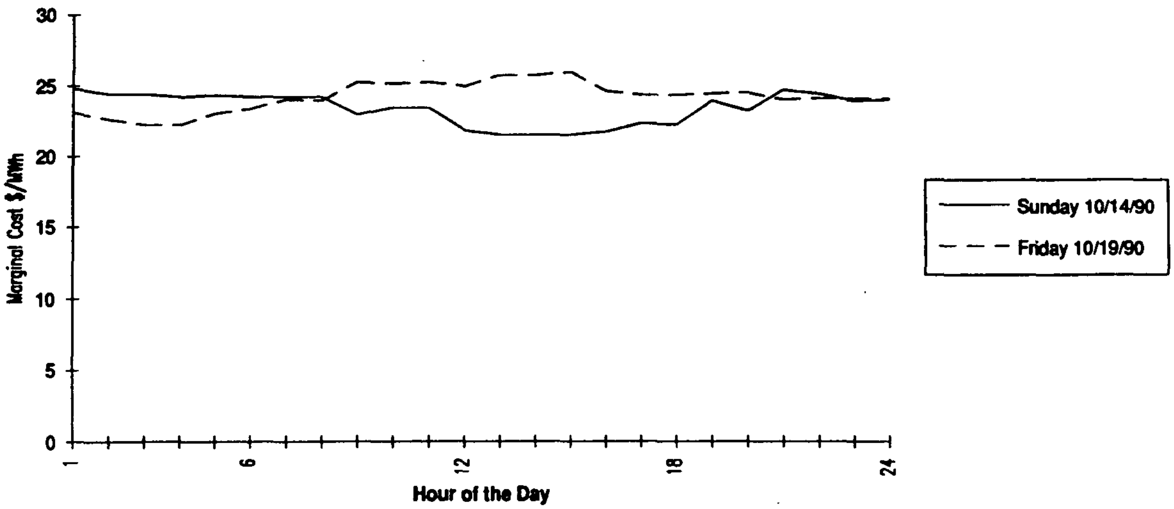

Figure B-5. Hourly Marginal Cost*—Fall 1990
—Fuel Price = $2.44/MMBtu—

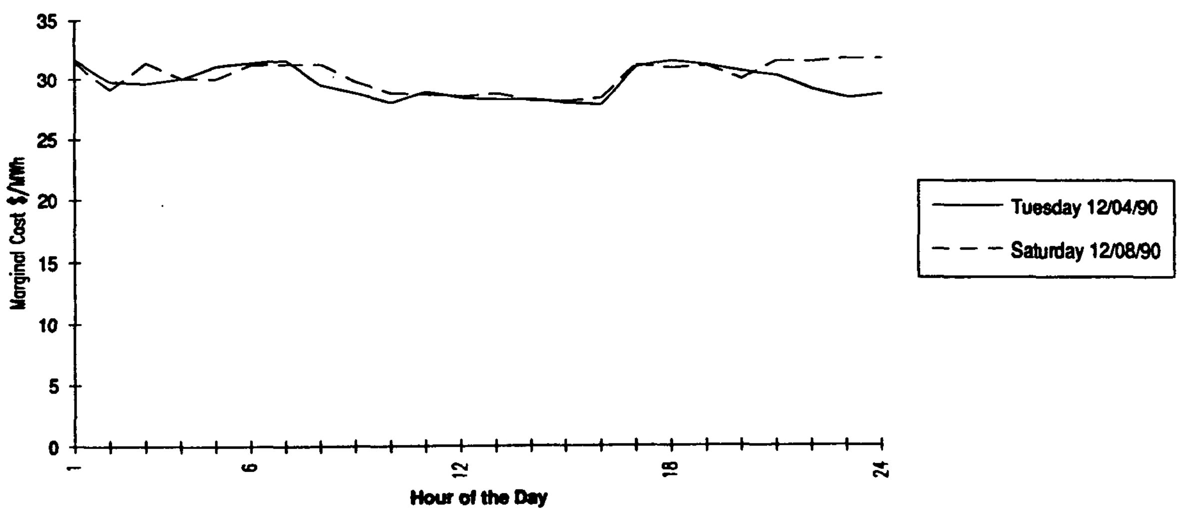

Figure B-6. Hourly Marginal Cost*—Winter 1990
—Fuel Price = $3.73/MMBtu—

*For on-system units only. Excludes off-system purchases.

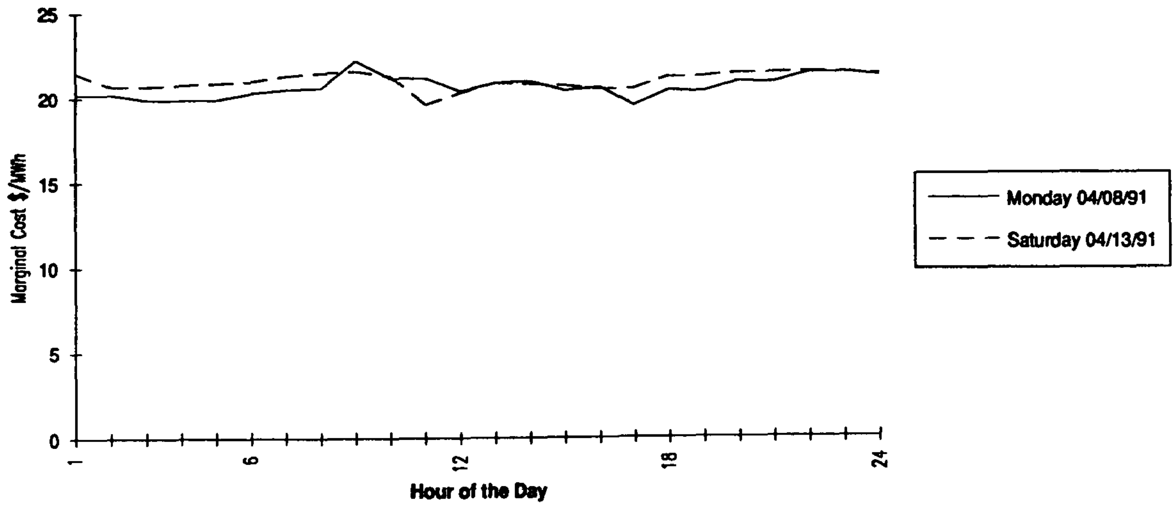

Figure B-7. Hourly Marginal Cost*—Spring 1991
—Fuel Price = $2.35/MMBtu—

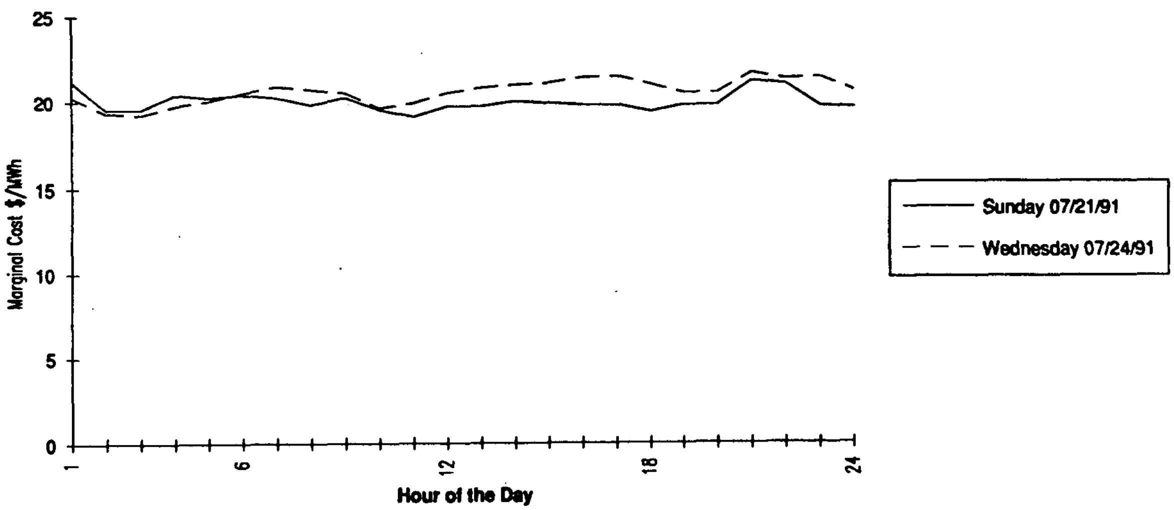

Figure B-8. Hourly Marginal Cost*—Summer 1991
—Fuel Price = $2.11/MMBtu—

*For on-system units only. Excludes off-system purchases.

C

TYPICAL DAILY SDG&E DISTRIBUTION SUBSTATION LOAD SHAPES

Appendix C presents typical daily SDG&E distribution substation load shapes. Figure C-1 presents the daily load for composite SDG&E commercial loads and residential loads. Figure C-2 presents the daily load shapes for the annual peak load day in September 1990 and for the monthly peak day in December 1989 for one of SDG&E's distribution substations.

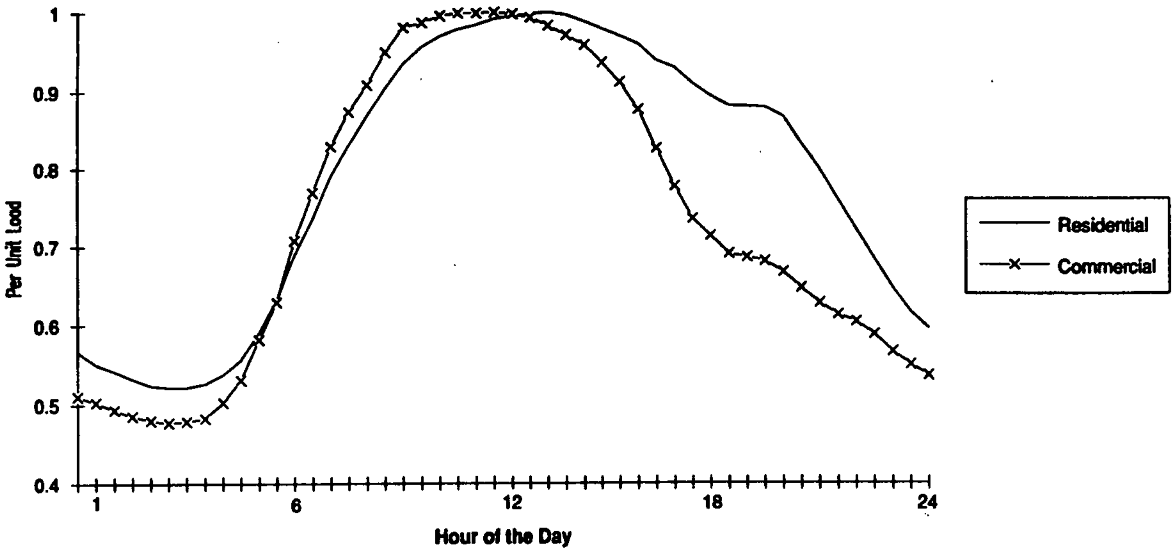

Figure C-1. Composite Daily Residential and Commercial Loads in 1/2 Hour Intervals

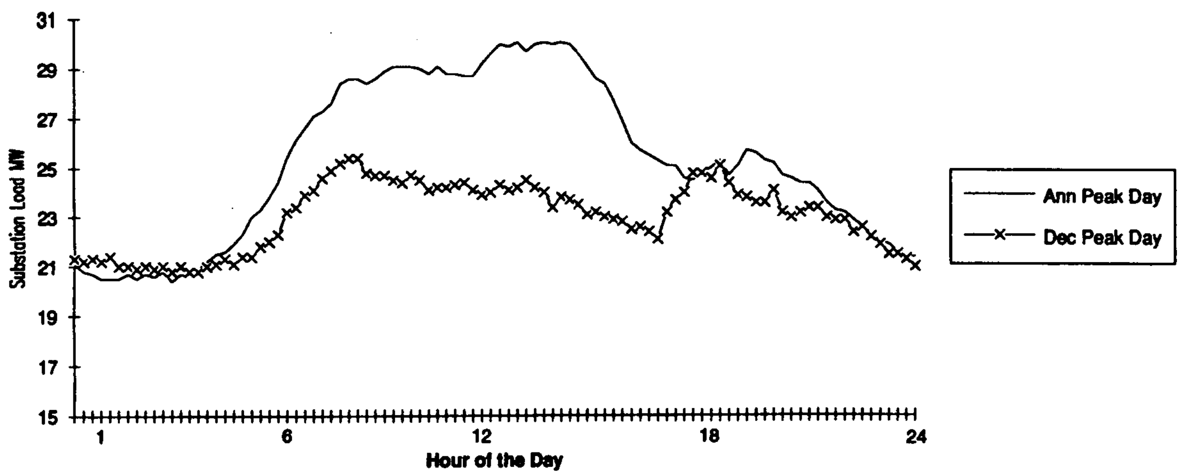

Figure C-2. Example SDG&E Substation 1/4 Hour MW Load For Annual Peak Day and December Peak Day

Appendix C

An Estimate of Battery Energy Storage Benefits on the Oglethorpe Power System

AN ESTIMATE OF BATTERY ENERGY STORAGE BENEFITS ON THE OGLETHORPE POWER SYSTEM

PTI Report No. 147-92

Prepared for:

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December 30, 1992

AN ESTIMATE OF BATTERY ENERGY STORAGE BENEFITS ON THE OGLETHORPE POWER SYSTEM

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ACKNOWLEDGEMENT

Power Technologies, Inc. wishes to acknowledge the help and cooperation received from many engineers and other staff members of Oglethorpe Power Corporation in supplying data and discussing their system characteristics and performance. The review and direction provided by both the Project Managers from Sandia National Laboratories and Oglethorpe Power Corporation was very helpful during the course of this study.

AN ESTIMATE OF BATTERY ENERGY STORAGE BENEFITS ON THE OGLETHORPE POWER SYSTEM

EXECUTIVE SUMMARY

Sandia National Laboratories sponsored this study, with cofunding from Oglethorpe Power Corporation (OPC), to determine if battery energy storage may be competitive with other options on the OPC system. Sandia's broader interest is to be a catalyst in the evolution of a market for battery energy storage technology among rural electric cooperatives (RECs) in particular and other utilities in general.

In this study, the potential role which battery energy storage could play

a) in providing a backup power source or an alternative to traditional fossil fuel distributed generation, and

b) deferment of new transmission and distribution facilities

in the Oglethorpe Power (OPC and EMCs) System were investigated.

The methodology consisted of evaluating and quantifying the reasonable benefits attainable from the battery storage applications and comparing the total benefits against the cost of the battery storage. Several benefits and the particular characteristics of the OPC system were reviewed and analyzed including:

- Load shape with and without direct load control
- Future generation expansion plan
- Role of pumped storage hydro and its impact on load leveling
- Cost of purchased power and energy
- Future transmission projects
- Future distribution projects
- Radial transmission lines/substations
- Need for backup power source.

Five specific locations within the OPC system, for the battery storage applications to defer transmission and distribution projects, were selected for this study. The battery sizes used for these five locations are shown in Table E-1.

TABLE E-1
SELECTED BATTERY SIZES

ITEMS	LOCATIONS				
	H	E	S	V	W
MWH	7.5	26.0	9.0	217.0	218.0
MW	1.5	6.5	1.5	31.0	43.6
HOURS	5	4	6	7	5

The results of a benefit to cost comparison are presented in Figure E-1. The methodology used for benefit to cost comparison is essentially based on calculating the present worth of all the annual cost savings/benefits accruing due to the battery application and the annual cost of owning and operating the corresponding battery plant.

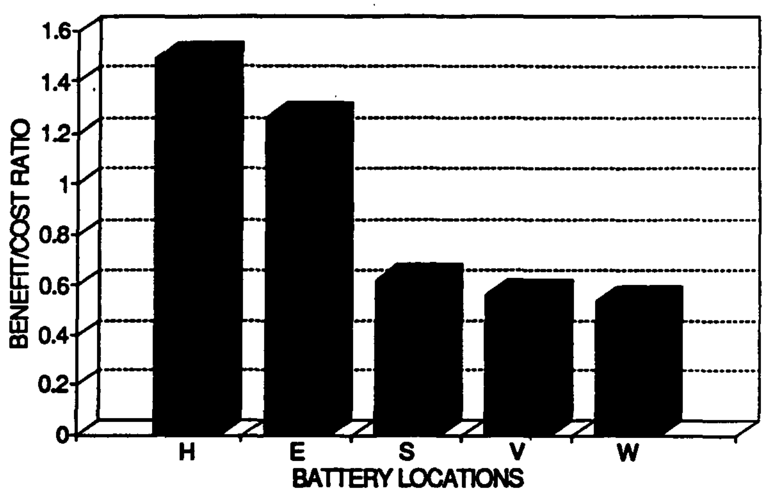


FIGURE E-1
COMPARISON OF BENEFITS TO COST
for 5 Battery Locations

Only four major benefits due to battery storage application are included in these benefits to cost ratios. They are:

- o Generation capacity
- o Transmission deferment
- o Distribution deferment
- o Value of service or cost of outage.

The battery storage identified in this study is mostly in the form of a backup or reserve source. It is not used in the general sense of load leveling. A generation capacity (KW) credit based on a 10 hour discharge rating is applicable. This battery KW (based on 10 hour discharge rating) is essentially a generation reserve source. A 10 hour discharge rating is used so that even if this reserve is called upon during the annual peak load condition, the battery will be in a position to provide the power (KW) equal to the credit it has received for the longest peak load period of 10 hours. Thus, for example, a 10 MW, 1 hour battery is given a credit of 1 MW. The cost of the battery credit is based on the least expensive or the preferred generation alternative, which is a combustion turbine. The annual cost savings from avoiding the investment in this generation is credited to the battery.

The transmission credit is basically computed on the basis of the cost of deferring the project. The actual capital cost expenditure is considered to be postponed by a number of years. The annual cost savings due to the postponement is credited to the battery benefits. The distribution benefits are also calculated similarly.

The fourth and last benefit computed in this study is the value of service or cost of outages. The interruption cost or value of service (VOS) data is considered to be suitable to relate the worth of service reliability to the cost of service. The value of service or outage costs depends upon type of load, frequency and duration of interruption and timing of the interruption. However, some of these costs have a wide range. The cost range for one hour interruption has been reported in the literature.

The actual cost or value of service used in this study is shown in Table E-2. For each of the five candidates of battery application analyzed in this study, it is assumed that the total amount of energy not served or KWH interrupted per year is equal to the total battery KWH rating. This means that, on the average, the sum of energy supplied to the customers by the battery during the interruptions over a period of one year is equal to its total energy rating.

TABLE E-2

VALUE OF SERVICE OR OUTAGE COST FOR ONE HOUR INTERRUPTION

	$/KWH Not Served	
1	Low	High
Residential[2]	0.05	5.00
Industrial[2]	2.00	53.00
Commercial[2]	2.00	35.00
Poultry & Eggs[1]	0.12	5.68

After computing benefits, the battery storage system costs were calculated. For the battery alone a different life is used than for the entire battery storage plant. The O&M used is 0.25% of the capital cost. Amortising the capital cost is levelized over the plant life. The salvage value of the battery cells is included in computing the levelized annual cost. The replacement cost of battery cells is included as needed. The converter and balance of plant are assumed to have a 30 year life and no salvage value.

Benefit to cost ratio for battery application at five different locations for T&D deferment have been computed. The percentage benefit the four items are shown in Figure E-2.

1 G. Walker and R. Billinton, "Farm Losses Resulting from Electric Service Interruptions - A Canadian Survey," IEEE Transactions on Power Systems, Vol. 4, No. 2, May 1989, pp 472-478.

2 A.P. Sanghvi et al, "Power System Reliability Planning Practices in North America", IEEE Transactions on Power Systems, Vol. 6, No. 4, Nov. 1991, pp 1485-1492.

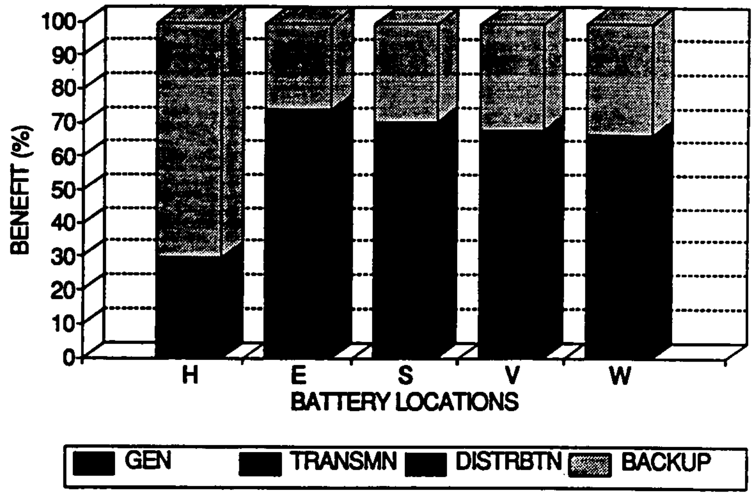


FIGURE E-2
PERCENT OF BENEFITS
for 5 Battery Locations

- o Backup source (considering cost of outage, value of service or value of unserved energy) credit was the most significant benefit from battery storage. In terms of customer loads on the OPC/EMC system, the poultry industry loads are considered to suffer high damage when service interruption occurs. Hence, some of these egg hatcheries and chicken farms currently provide, or plan to install backup diesel generation. Application of a 7,500 KWH, 5 hours discharge rating battery at Hollywood substation showed a benefit to cost ratio of 1.5. This was one of the highest benefit to cost ratios obtained in this study.

- o Whenever there is an outage on a radial line, an interruption of service occurs. If the line is inaccessible or has difficult terrain, then repair of the line may be difficult and corresponding outage may be lengthy . One such example selected for this study was the application of a battery for backup instead of building a second transmission line. The benefit to cost ratio is 1.26 for this case. This substation is an attractive location (out of the 5 analyzed) for the battery application and deferment of a second transmission line.

- o A third substation was selected for evaluating the deferment of a new distribution transformer. The benefit to cost ratio turned out to be 0.62. The generation capacity credit was the largest, followed by the backup source credit with distribution credit being the least. No transmission deferment was used in this example. A higher backup source credit in lieu of new transmission line credit may be warranted here. The value of service has to be $8.00/KWH for breakeven of benefit to cost ratio as compared to $2.61/KWH (used in the base case for the ratio of 0.62).

- o Deferment of an additional 140 MVA, 220/115 kV transformer at two substations were evaluated. The benefit to cost ratios were 0.57 and 0.54 respectively. Because of parallel 230 kV and 115 kV lines connected to these substations, oversize battery storage capacity was needed to provide a given load reduction on the existing transformers. Hence, the size of the battery and its cost would be about twice that required to reduce load on a radially connected transformer; in which case the benefit to cost would be nearly breakeven.

In addition to base cases, several sensitivity analyses were performed for the highest benefit to cost application. The sensitivity analysis included changing the following parameters, one at a time:

- o Battery cost
- o Converter and balance of plant cost
- o Battery life
- o Salvage value
- o Value of service/cost of outages
- o Extended distribution benefits.

In the first case, the battery's cost can be 60% higher than the base case, for the value of benefits to equal the cost of battery storage. In the second case, the converter and balance of plant (PCS + BOP) cost was doubled and this reduced the benefit to cost ratio from 1.49 to 1.27. These two sensitivity cases show that the battery cells cost has a higher effect on the overall cost as compared to the converter and other costs.

In the third case, the battery life was reduced to 10 years from 15 years. This means two battery replacements are included in this case-3 as compared to only one battery replacement in the base case. The benefit to cost ratio decreased from 1.49 to 1.42 which is not a substantial reduction. Thus, there may be economic advantages in improving the cycle life of lead acid batteries, but the chronological life is not significant as compared to the battery cost itself.

In the fourth case, the salvage value was doubled from 20%. Surprisingly, the benefit to cost ratio increased to 1.68. This may be partly explained by the escalation used in computing replacement battery cost. Essentially, the salvage part of the battery cost is escalated by 4.5% because at the end of battery life, the trade-in value of the battery is assumed to be equal to the salvage percentage of the new battery cost.

The fifth sensitivity case involved the value of service or backup source credit. As noted earlier, this item contributed most to the battery benefits. This value of service may be about 50% of the base case for the breakeven cost.

In the sixth sensitivity case, the distribution benefits were extended to 30 years. The base case showed the distribution transformer deferment for 10 years only. Because the battery can be moved to another location, similar distribution benefits may continue to accrue. This case shows an increased benefit to cost ratio of 1.58. The cost of moving the battery and any change in value of service are not recognized in this case.

AN ESTIMATE OF BATTERY ENERGY STORAGE BENEFITS ON THE OGLETHORPE POWER SYSTEM

1.0 INTRODUCTION

The purpose of this study was to identify the potential role battery storage could play in providing equal or better performance than other traditional transmission and distribution (T&D) options, such as adding new T&D facilities and equipment in the Oglethorpe Power System.

Sandia National Laboratories sponsored this study, with cofunding from Oglethorpe Power Corporation (OPC), to determine if battery energy storage may be competitive with other options on the OPC system. Sandia's broader interest is to be a catalyst in the evolution of a market for battery energy storage technology among rural electric cooperatives (RECs) in particular and other utilities in general.

This study verified recent concurrence that justification of battery energy storage should be analyzed differently as compared to most other utility equipment, including other forms of storage. Most utility equipment serves only a single purpose, and is justified only if it serves that purpose. Examples are generating plants which serve only a single purpose regardless of where they are located. A distribution substation also serves just one purpose, though it must be in the proper place to do so. Batteries, potentially, provide several 'resource' benefits, several T&D benefits, and even some 'strategic' benefits. A proper evaluation requires that every possible benefit be investigated and quantified. A battery is justified if the sum of all of the benefits exceeds its cost.

The approach through most of this study is thus to avoid comparing battery costs with individual benefits. In fact, the cost of a battery is not given any consideration until all possible benefits have been identified and estimated.

This study is not thorough enough to truly 'quantify' all the benefits of batteries on the OPC system. Indeed, the intent of the study is to estimate the benefits with sufficient accuracy to determine whether more in-depth studies are warranted.

The main conclusions from this study are presented in Section 2.0. The generation and transmission perspective for this type of study is discussed in Section 3.0. Section 4.0 describes the characteristics of the Oglethorpe Power System. The generation related benefits from battery storage are discussed in Section 5.0. Potential transmission and distribution benefits are evaluated in Sections 6.0 and 7.0 respectively. Summation of these benefits and cost-benefit comparison are presented in Sections 8.0. Four appendices contain brief descriptions of battery storage benefits, terms, attributes, and hardware and control.

2.0 CONCLUSIONS

In this study, the potential role which battery energy storage could play

a) in providing a backup power source or an alternative to traditional fossil fuel distributed generation, and

b) deferment of new transmission and distribution facilities

in the Oglethorpe Power (OPC and EMCs) System were investigated.

The methodology consisted of evaluating and quantifying the reasonable benefits attainable from the battery storage application and comparing the total benefits against the cost of the battery storage. Several benefits and the particular characteristics of the OPC system were reviewed and analyzed including

- o Load shape with and without direct load control
- o Future generation expansion plan
- o Role of pumped storage hydro and its impact on load leveling
- o Cost of purchased power and energy
- o Future transmission projects
- o Future distribution projects
- o Radial transmission lines/substations
- o Need for backup power source.

The detailed results from this review and analysis for five specific locations within the OPC system are presented in this report. The main conclusions are:

i. Backup source (considering cost of outage, value of service or value of unserved energy) credit was the most significant benefit from battery storage. In terms of customer loads on the OPC/EMC system, the poultry industry loads are considered to suffer high damage when service interruption occurs. Hence, some of these egg hatcheries and chicken farms currently provide, or plan to install backup diesel generation. Habersham #8 (Hollywood) Substation serves a substantial number of these chicken farms. Application of a 7,500 KWH, 5 hours discharge rating battery at Hollywood substation showed a benefit to cost ratio of 1.5. This was one of the higher benefit to cost ratios obtained in this study.

ii. The OPC system has approximately 24 substations served by radial subtransmission lines. Whenever there is an outage on a radial line, an interruption of service occurs. If the line is inaccessible or has difficult terrain, then repair of the line may be difficult and corresponding outage may be lengthy . One such example selected for this study is Planters #9 (Egypt) substation. Application of a battery for backup instead of building a second transmission line was analyzed. The benefit to cost ratio is 1.26. This Egypt substation is an attractive location (out of the 5 analyzed) for the battery application.

iii. Satilla #12 (Lanes bridge) substation was selected for evaluating the deferment of a new distribution transformer. The benefit to cost ratio turned out to be 0.62. The generation capacity credit was the largest, followed by the backup source credit with distribution credit being the least. No transmission deferment was used in this example. A higher backup source credit in lieu of new transmission line credit may be warranted here. The value of service has to be $8.00/KWH for breakeven of benefit to cost ratio as compared to $2.61/KWH (used in the base case for the ratio of 0.62).

iv. Deferment of an additional 140 MVA, 220/115 kV transformer at both Vidalia and Warranton substations were evaluated. The benefit to cost ratios were 0.57 and 0.54 respectively. Because of parallel 230 kV and 115 kV lines connected to these substations, oversize battery storage capacity was needed to provide a given load reduction on the existing transformers. Hence, the size of the battery and its cost would be about twice that required to reduce load on a radially connected transformer; in which case the benefit to cost would be nearly breakeven.

v. High on-peak energy purchase price makes a load leveling type of application very attractive. However, the existing direct load control (DLC) and the Rocky Mountain pumped storage hydro (PSH) plant under construction provide most of the load leveling function for the OPC transmission system. Battery Energy Storage would be more appropriate for Distribution.

vi. Analysis for peak load shape, after factoring the DLC and PSH, shows that a generation reserve capacity credit for the battery storage based on a ten hour discharge period may be given. For example, a 10 MWH battery rated for 1 hour discharge may be given 1 MW generation reserve capacity credit.

vii. Other generation credits such as spinning reserve, load following and area regulation are present. But these benefits are considered to be small and difficult to quantify. The future operation of PSH will provide considerable spinning reserve benefits. Any leftover benefits for the battery storage will be insignificant.

3.0 THE G&T PERSPECTIVE

Rural Electric Cooperatives, (RECs), are consumer-owned utilities established to provide electricity service to rural America. Historically, most U.S. farms were without electric power until the mid-1930s because large, investor-owned utilities could not economically justify building distribution lines to the low customer density rural areas. In 1935, President Franklin D. Roosevelt signed an executive order creating the Rural Electrification Administration (REA), an arm of the New Deal that worked to form rural America into cooperatives to put up their own power lines. As a result of the order, more than 1,000 distribution cooperatives were formed, and they immediately began constructing lines to rural areas. By 1939, over 100,000 miles of power lines had been completed and more than one million rural residents received electricity. Today, over half the electric distribution lines in the U.S. are owned and maintained by cooperatives. These cooperatives distribute about 7 percent of the nation's electricity.

Typical rural electric cooperatives maintain almost 2,000 miles of line and serve close to 8,000 customers. Residential customers account for about 90 percent of the cooperative's total customers, while approximately 8 percent of the cooperative's customers are commercial. Rural electric cooperatives (RECs) average five consumers per mile. Investor-owned utilities average 31 customers per mile of line.

The low customer density on rural electric transmission and distribution systems makes RECs cost of transmission and distribution much higher, per customer, per Kw of peak load, or per Kwh sold, than that of most municipal or investor owned electric utilities. T&D costs are also high for RECs because T&D systems must be designed to accommodate the local peak load, and many REC systems have a relatively poor load factor. Because battery energy storage can be used to defer T&D investments, its T&D deferral benefit on REC systems may be very significant.

The rural low density nature of REC systems also affects the reliability that can be economically justified. Similarly, because of extensive line exposure, maintaining power quality is difficult on rural REC systems. Batteries can provide a local source of power, largely independent of the transmission system, and thus can be used to improve reliability and power quality.

Another consequence of long lines and low customer density is high T&D losses. By charging batteries at night and discharging them during the peak load hours, T&D losses can be measurably reduced.

Among all types of rural electric cooperatives, the generation and transmission cooperatives (G&T) appear to be the most likely to adopt battery energy storage. There are over 60 G&T cooperatives, ranging in size from the smallest, serving about 6,000 customers with an annual operating revenue of $5 million, to the largest, Oglethorpe Power, serving nearly 900,000 customers (through distribution cooperatives) with annual revenue of about one billion dollars.

Generation and transmission cooperatives have the construction and operation experience that would allow them to successfully build and maintain battery energy storage systems. In 1988, G&T cooperatives had 239 generating plants with an overall generating capacity (nameplate) of over 30,000 MW. Steam generating plants are the G&T cooperatives' chief source of energy, producing 86 percent of the total generated. Generation at internal combustion plants accounted for 2.5 percent of the total, while nuclear and hydroelectric production amounted to 11.3 percent and 0.2 percent respectively. With their considerable experience in generation, cooperatives would have no foreseeable difficulties designing, constructing, operating and maintaining battery energy storage facilities.

In summary, rural electric cooperatives have many of the aspects of large, sophisticated electricity customers. Many of them pay significant demand, energy, and/or power factor correction charges which can yield significant savings when peak demand is reduced. Generation and transmission cooperatives have the size, strength, and experience to construct and operate a battery storage facility and are in a position to take advantage of reduced capital costs and operating flexibility. The introduction of battery energy storage to the electric utility industry through this market segment can be an effective strategy.

4.0 CHARACTERISTICS OF THE OGLETHORPE POWER SYSTEM

Oglethorpe Power Corporation (OPC) was formed in 1974 by 39 of Georgia's 42 electric membership corporations (EMCs) for the purpose of supplying electricity to its founding members. Today, OPC serves over 71 percent of the area in the State of Georgia and is one of the largest generation and transmission (G&T) cooperatives in terms of number of ultimate customers and annual kilowatt hour sales.

Oglethorpe Power's generation capacity has traditionally been provided by joint ownership and lease agreements with the local investor-owned utility. Most of the base load capacity is provided by the Hatch and Vogtle nuclear, and Scherer and Wansly coal plants. However, load growth has primarily been in the form of peaking power. In 1988, peak demand grew by 8.6 percent while energy demand increased by 5.8 percent. Furthermore, system growth provided the incentive for Oglethorpe Power Corporation to build its own generation facilities. Thus, OPC has pursued a course of building facilities that best provide peaking power. This includes the 2.1 MW Walter H. Harrison hydroelectric plant and the 760 MW Rocky Mountain pumped storage plant which is under construction.

The cooperatives supplied by OPC are spread throughout the State of Georgia. Along with the other utilities, OPC shares about 15,000 miles of transmission network. OPC, along with other participants, have pioneered the concept of an integrated transmission system (ITS). The ITS agreement allows the participants to use any transmission line or substation on the network. Each participant buys into the existing transmission system based on the contribution to the coincident and non-coincident annual amount of power the supplier transmitted over the system. Thus, there is considerable incentive to reduce the annual peak load imposed on the transmission system by each participant.

OPC is in another unique situation. In the State of Georgia, customers with connected loads greater than 900 kw (referred to as "customer choice load") can select their power supply from any EMC or other utility within the state. Thus, there is considerable competition for these "customer choice loads." Obviously, cost, reliability, and quality power are important in winning these "choice customer loads". This competitive factor, not an influential factor for most electric utilities, is an important factor for OPC and its member cooperatives.

The investigation and adoption of advanced technologies, such as Battery Energy Storage, is a natural outcome of OPC's need to supply peaking power, minimize cost of extensive transmission system, and compete for customer choice loads. Battery energy storage is promising to Oglethorpe Power Corporation because of unique features such as:

- Peaking power without new generation capacity construction;
- Flexible size (modular) and siting (existing substation locations);
- Additional value to customers such as improved power quality and/or reliability;
- Offers system operation benefits and flexibility;
- Transmission and distribution benefits such as substation or line deferral;
- ITS parity benefits.

OPC, jointly with Electric Power Research Institute, is also investigating other options. A parallel study entitled "Assessment of the Benefits of Distributed Fuel-cell and Diesel Generators" is also underway.

4.1 Load Characteristics

OPC had a peak load of 3,883 MW in 1991. The load is forecast to grow to nearly 6,000 MW by the year 2000. The load is summer peaking. During winter, the daily peaks are sharp, but the peaks are lower than summer peaks (Figure 4.1). The summer peaks are almost flat and last 6 -8 hours in the afternoons (Figure 4.1). The winter load profile has twin peaks, with the early morning peak sharper and higher than the evening peak. The annual load factor of the native load is about 45 percent. Most (95 percent) of the ultimate customers are residential, accounting for about 75 percent of the annual energy, and hence the low load factor. Out of 74 substations which were examined, 12 substations showed sharp peaks. In terms of future load, OPC forecasts that about 7 EMCs may contribute about 70 percent of the growth.

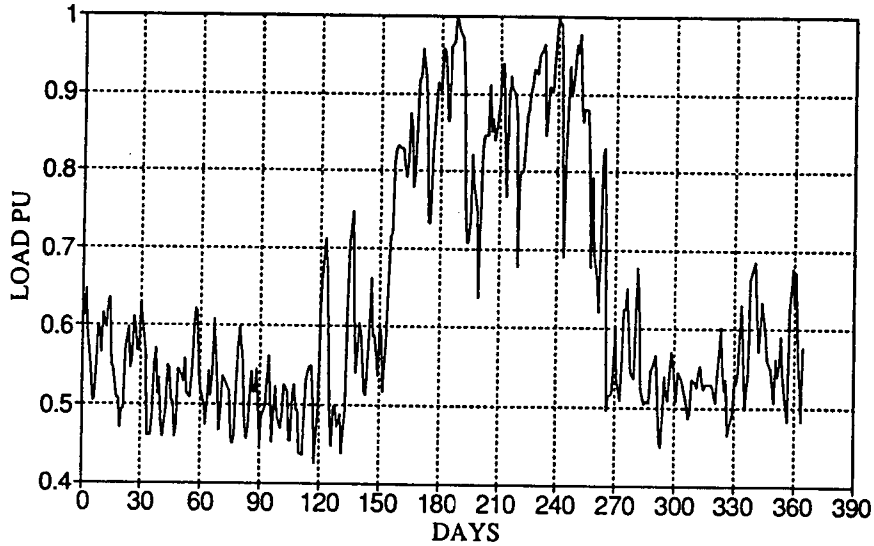


FIGURE 4.1

OPC SYSTEM DAILY PEAKS IN PU

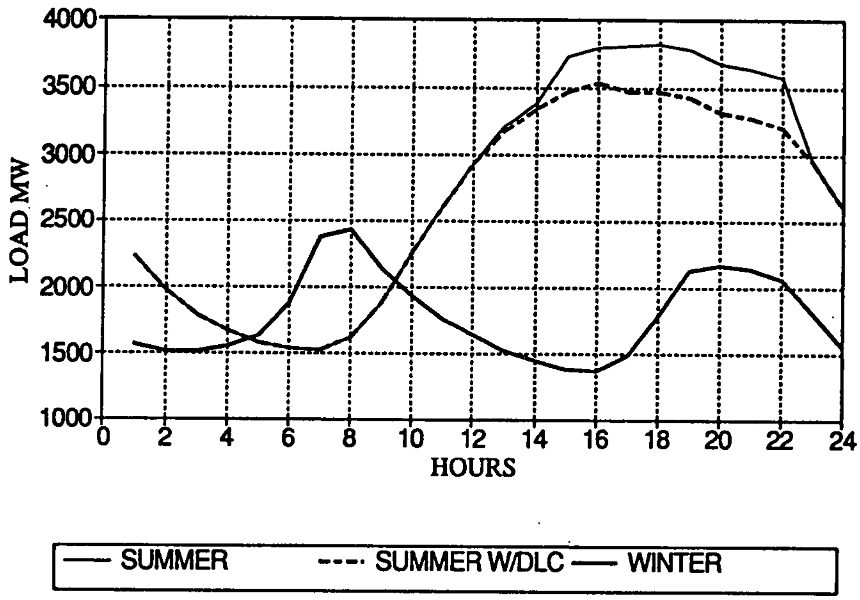


FIGURE 4.2

PEAK DAY LOAD SHAPE IN 1991
WITH & W/O DIRECT LOAD CONTROL

4.2 Generation

OPC's generation mix includes part ownership in two nuclear power plants amounting to 1155 MW by the year 1994, some base load coal plant capacity, and hydro power purchase from federal agencies (up to 542 MW). The remaining requirement is purchased from other utilities. OPC is building a pumped storage facility called Rocky Mountain Project with 760 MW of capacity. This plant is expected to be in service in 1996 and OPC owns a capacity of 651 MW.

4.3 Purchase Power

OPC purchases power to meet part of the load requirements of its member cooperatives. The purchased power is in blocks of 250 MW each with about 15 percent reserve (35 MW) included in this block. A notice of 12-24 hours is required to purchase base load capacity and energy. Otherwise, the purchased power is considered to be peaking capacity and energy which has a higher energy charge.

TABLE 4.1

MONTHLY COMPONENT BLOCK RATES FOR YEAR 1991

Blocks 1 - 3	250 MW	$6.50/kw/month	20.93-23.79$/MWH
Block 4	250 MW	$7.10/kw/month	27.52 $/MWH
Blocks 5 -6	215 MW	$1.25/kw/month	70.15$/MWH

4.4 Load Management

Nearly 300,000 direct load control (DLC) switches have been installed to control airconditioners and water heaters in most of the EMCs. The water heaters can be shut off for long periods (hours). Airconditioners are cycled at 7 minute intervals. The peak load reduction provided by load management in 1991 is estimated to be 350 MW. The peak day load profile with and without load management for the year 1991 is shown in Figure 4.2. OPC estimates that there may be another 150 MW of load management potential available within the system by expanding the direct load control.

4.5 Integrated Transmission System

OPC, along with other utilities in the state, has implemented the concept of an integrated transmission system (ITS). The concept is based on the assumption that each user buys into the existing transmission system based on the amount of power each transmits over the system. The noncoincident peaks are used in calculating the required investment for all participants except for Georgia Power Company. Annual fixed charges of owner companies are used in calculating the parity payments for each participant should a participant be over or under invested in the ITS. The load management system presently used by OPC fits into this strategy very well. Any other demand side option will also be useful for this purpose.

5.0 GENERATION RELATED BENEFITS

Three generation related benefits assigned to battery storage when used for load leveling are:

1. battery storage MW capacity credit associated with displacing other generation alternatives in the resource plan,

2. production cost savings associated with daily cycling (charge/discharge) of batteries, and

3. dynamic benefits from reduced unit startup and shutdown to meet spinning reserve and load following obligations.

These three benefits, as applicable to the OPC system in particular, are discussed in the next three sections.

5.1 Generation System Reliability Benefit on the OPC System

Generation system reliability criteria used to determine the required installed generation capacity consists of both deterministic and probabilistic criteria. This criteria varies from utility to utility. Generally, deterministic reliability criteria may include:

- o Percent MW Capacity Reserve
- o Percent Mwh Energy Reserve (Adverse Hydro Condition)
- o Combination of above

Probabilistic criteria may include:

- o LOLE (Loss of Load Expectation)
- o Expected Unserved Energy
- o Frequency and Duration

Generally, in order for a battery to obtain credit and defer generation additions, a utility must need new generation capacity in the time frame being studied. For example, batteries cannot obtain capacity credit if a utility already has excess capacity installed, even though batteries may further increase generation system reliability. Also, in order to obtain capacity credit, batteries must meet the generation reliability criteria.

Batteries do not necessarily have to operate on a daily charge/discharge cycle to obtain capacity credit. However, to provide this benefit batteries may need several hours of storage. For example, assume a utility uses a deterministic percent reserve criteria, or a basic LOLE criteria using only daily one-hour peak MW loads. Because batteries are energy limited, it's unlikely that a one hour battery will be acceptable when common sense is applied, although it may technically meet the reliability criteria.

The peak load forecast for the OPC system, with and without direct load control (DLC) is shown in Table 5.1. As evident from this table, OPC needs additional capacity in the future years, so if batteries are applied, then a capacity credit is certainly applicable.

TABLE 5.1

OGLETHORPE POWER COMPANY
LOAD FORECAST DATED MARCH 13, 1991

Year	Peak Load (MW)	Annual Energy (GWH)	Peak MW With DLC (a)	Additional Capacity Needs (MW)
1992	4,281	16,978	3,936	158
1993	4,465	17,696	4,102	156
1994	4,671	18,458	4,289	297
1995	4,863	19,219	4,462	(171)
1996	5,049	20,023	4,630	37
1997	5,280	20,846	4,843	298
1998	5,516	21,687	5,060	564
1999	5,767	22,629	5,293	849
2000	6,044	29,174	5,551	1,165
2001	6,330	24,692	5,819	1,515
2002	6,606	25,743	6,076	1,963
2003	6,873	26,842	6,324	2,303
2004	7,171	27,996	6,604	2,838
2005	7,473	29,174	6,887	3,185
2006	7,774	30,230	7,169	3,515
2007	8,137	31,549	7,514	4,000
2008	8,501	32,875	7,860	4,424
2009	8,814	34,237	8,154	4,837
2010	9,127	35,643	8,449	5,237

The next question is to determine what capacity credit is applicable to the battery. In principle, the capacity credit or benefit will equal the lowest cost new generation alternative, which is combustion turbine.

As mentioned earlier, capacity credit may not be reasonable if the battery has just one hour of storage. A discharge rating such as one hour may not be sufficient to avoid a new peak or the need to purchase power in blocks 5 or 6 over the relatively long peak load period. However, the deterministic criteria of 15% reserve is based on peak load only. Thus, only the peak day load shape needs to be examined to determine the number of hours of battery capacity required to qualify for credit. Peak load shape for the year 1991 is shown in Figure 5.1. Both the native load and the load after load management (direct load control) are shown. Based on this load shape, the following hour ratings are required to qualify for capacity credit.

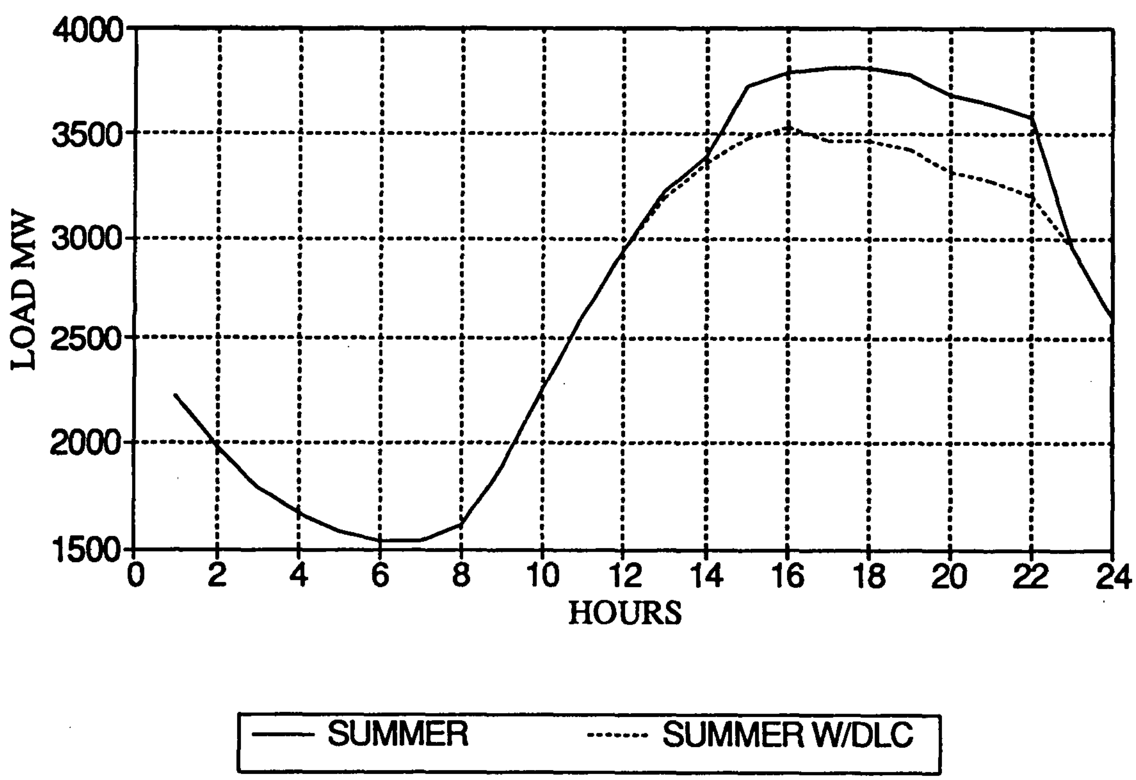


FIGURE 5.1
PEAKDAY LOAD SHAPE WITH & W/O DIRECT LOAD CONTROL

TABLE 5.2
PEAK ENERGY REQUIREMENTS WITH DIRECT LOAD CONTROL

Capacity (MW)		Discharge Hours	Total MWH Rating
Block	Cumulative		
60	60	2	120
next 4	64	4	136
next 44	108	5	356
next 69	177	6	770

TABLE 5.3
PEAK ENERGY REQUIREMENTS (WITHOUT DIRECT LOAD CONTROL)

Capacity (MW)		Discharge Hours	Total MWH Rating
Block	Cumulative		
7	7	1	7
next 18	25	2	43
next 14	39	3	85
next 48	87	4	277
next 52	139	5	527
next 36	175	6	743

The amount of load reduction due to load management is very much weather dependent. There is also a saturation effect of load management. Thus, battery storage may supplement DLC and also act as a reserve capacity.

The discharge hours shown in the above two tables are applicable only until the end of 1995. OPC is constructing a pumped storage hydro (PSH) facility with an in-service date of late 1995 or early 1996. The weekly load shapes for both summer and winter are shown in Figures 5.2 and 5.3 respectively. The PSH discharge and pumping shown in these figures have been determined by using Production Costing Program, and hence, all restrictions and economics have been enforced. The use of the PSH facility flattens the peak load to more than 10 hours. Thus, any capacity credit for a battery on the OPC system beyond 1996 requires a ten hour discharge rating. The MW capacity attributable to the battery will be based on this discharge requirement. However, some credit is justified even for a 1 hour battery. For instance, a 10 MW 1 hour battery could provide 1 MW for 10 hours, and will be given a 1 MW capacity credit.

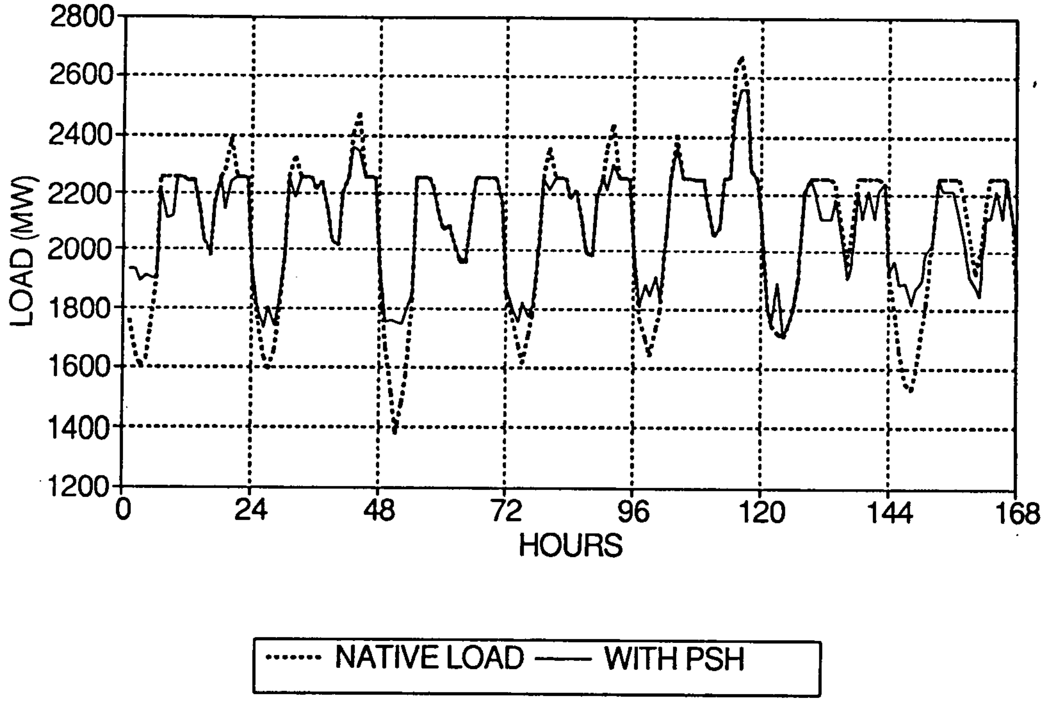


FIGURE 5.2
WINTER WEEKLY LOAD SHAPE WITH & W/O PSH

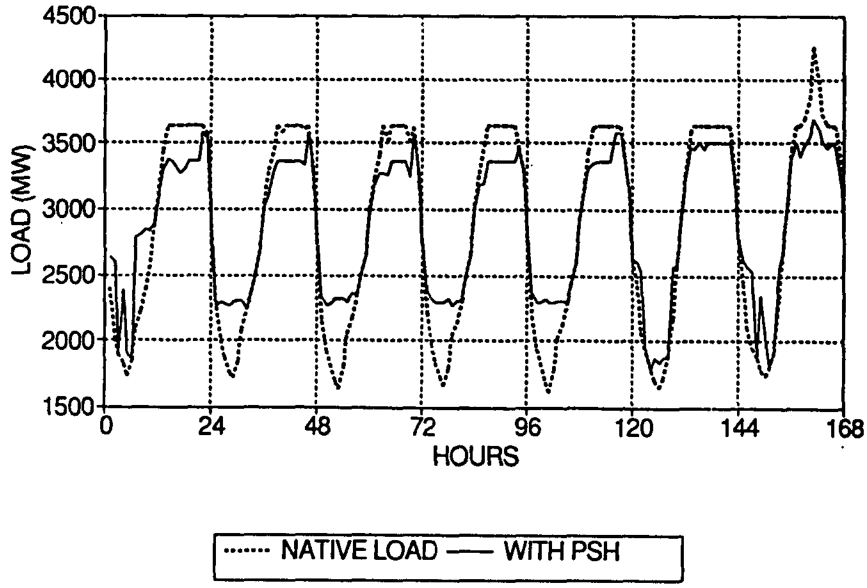


FIGURE 5.3
SUMMER WEEKLY LOAD SHAPE WITH & W/O PSH

5.2 Production Cost Savings

Production cost savings are generally determined by running a production cost program over a period of time with and without batteries to determine the fuel savings associated with charging and discharging the battery on a daily cycle. Batteries operating on a regular daily charge/discharge cycle (load leveling) will significantly reduce system production cost if there is significant fuel cost differential between peak and off-peak load periods.

Production cost savings from battery energy storage is conditioned on:

1. A cost differential between on-peak and off-peak energy cost sufficient to cover battery turn-around losses,

2. A modest peak load duration (several hours or less),

3. Good battery life under cycling duty.

The on-peak energy cost (usually the cost of burning oil or gas in combustion turbines) is higher than the off-peak energy cost on the OPC system. Battery storage systems typically have a turnaround efficiency of 70% to 80%. Hence, the ratio of the off-peak and on-peak energy cost should be greater than 1.25 (assuming 80% efficiency) to result in any production cost savings.

5.2.1 Differential Cost of Energy

OPC purchases a part of its power need from other utilities. The forecast of cost of purchased energy and corresponding ratio of on-peak to off-peak energy is shown in Table 5.4.

TABLE 5.4

RATIO OF ON-PEAK TO OFF-PEAK PURCHASED ENERGY COST

YEAR	ON-PEAK mills/kwh	OFF-PEAK mills/kwh	RATIO
1992	70.15	20.93	3.4
1993	70.20	21.87	3.2
1994	84.05	19.28	4.4
1995	100.62	17.78	5.7
1996	107.88	18.50	5.8
1997	115.61	19.31	6.0
1998	123.89	20.13	6.2
1999	132.76	20.97	6.3
2000	142.27	28.05	5.1
2001	149.97	29.35	5.1
2002	163.35	30.76	5.3
2003	173.03	32.27	5.4

Assuming round trip battery efficiency of 75% (middle of 70%-80% range), ratio of on-peak to off-peak energy cost of 1.33 is a break-even point. The ratios shown in the above table are considerably higher than the break-even point. Thus, the purchased energy cost differential is very favorable. For example, for every kwh of discharge from the battery, the savings are

$$70.15 - (20.93/0.75) = 42.24 \text{ mills/kwh}$$

using 1992 purchased energy costs.

Recognizing the big cost differential between peak and off-peak energy costs, OPC is constructing a PSH facility due for commissioning in 1996. OPC's share of this PHS is about 650 MW. The PSH will function similarly to the battery and a typical peak day load shape before and after the PSH use is shown in Figure 5.4. As discussed earlier, the final load shape, after load management (this is seasonal) and PSH load leveling, becomes flat for periods of 10 hours or longer. The available charging off-peak capacity and energy which is economical also becomes limited. Thus, any potential credit due to capacity peaking reduction and peak energy savings through battery storage is negligible for OPC.

5.3 Spinning Reserve Benefits

Operating reserve criteria vary from utility to utility and NERC region to NERC region. Operating reserve policy generally consists of on-line MW spinning reserve requirements plus additional off-line quick start generation capable of responding within a specified time period (10-30 minutes). Spinning reserve typically includes unused MW capability of generators operating at partial load to provide area regulation plus additional on-line units operated at partial load to cover sudden loss of generation.

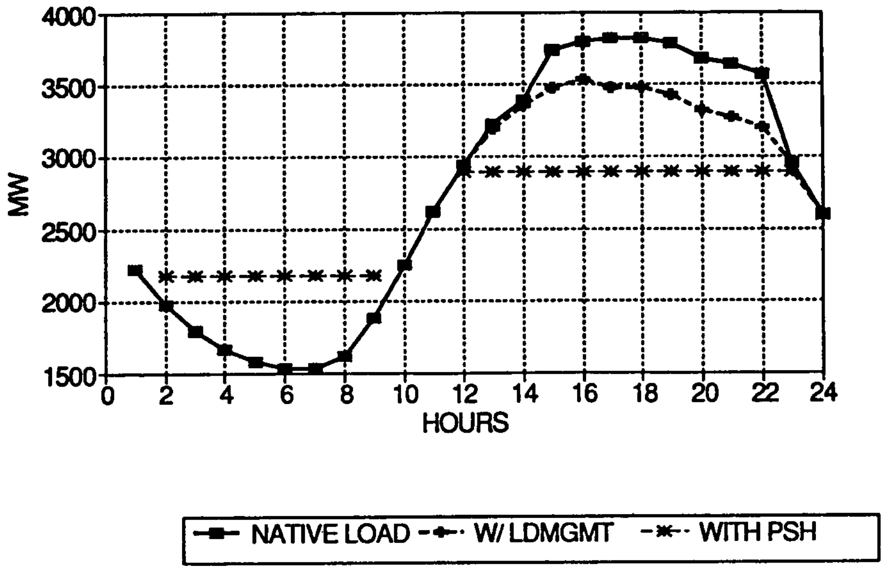


FIGURE 5.4

PEAKDAY LOAD SHAPE WITH DLC & PSH

Since batteries have the capability to be quickly started or changed from charging to discharging in the millisecond time frame, batteries can be used to supply the spinning reserve requirement. The potential benefit will depend on the type of generation used for spinning reserve.

Potential economic benefits from battery storage systems are expected to include:

- o More efficient operation of units that would otherwise operate at partial load to provide spinning reserve,
- o Cost savings from not running higher cost units that would otherwise have to operate to provide spinning reserve.

Batteries would be expected to operate infrequently to supply MW spinning reserve capability. It is also expected that batteries used for this application would only have to operate until other generation could be started or purchased after sudden loss of a generating unit. Hence, batteries used for spinning reserve would probably not require large MWh storage capability.

The Southern subregion has adopted a policy of using 1.5 times the capability of the largest in-service generating unit as a "target" Operating Reserve. Oglethorpe Power will be responsible for a portion of the Southern subregion "target" Operating Reserve proportional to its responsibility for the Southern subregion's peak load.

The Southern subregion policy further stipulates that at least 50% of the Operating Reserve must be Spinning Reserve to provide for normal regulating margin and a portion, more than 50%, of the loss of generation that would result from the most severe single contingency.

Based on the peak loads of Southern Company and OPC for the year 1991 and the largest generating unit size of 1113.5 MW, the spinning reserve responsibility for OPC is 189 MW. OPC is using 200 MW as spinning reserve requirement.

Calculation of potential economic benefits associated with using batteries for spinning reserve requires determination of expected costs resulting from operating Southern Company and OPC generating units, with and without spinning reserve requirements shifted to batteries. Unfortunately, in large systems of 30,000 MW plus capacity, small battery storage installations of a few MW rating would show a very small or no change in the production cost. The production cost difference may be in the same range as the confidence in the magnitude of the total production cost of the system. Besides, OPC may anticipate a spinning reserve credit for Rocky Mountain Pumped Storage Facility especially during pumping and other times, due to the hydro units fast startup capability. Also, once load management can be directly effected by Oglethorpe Power's System Control Operators, the interruptible load can be credited towards Oglethorpe Power's Operating Reserve. Hence, no production costing simulations were made to determine the spinning reserve credit. For battery systems of a few MW rating on the OPC system, spinning reserve credit may be considered negligible.

5.4 Other Generation Related Benefits

There are at least four more readily identifiable benefits which may be attributable to battery energy storage systems. They are:

-- reduced minimum load problems

-- provide area and frequency regulation

-- reduce operating constraints

-- reduce deviations from economic dispatch

These benefits are sometimes referred to as "dynamic" benefits of battery storage.

Utility systems, with large base load units and a relatively low minimum load, experience difficulty in dispatching during off peak hours. Economic dispatch, unit minimum load limits and minimum down time requirements of base load units cause this problem.

Batteries may be employed to more economically solve these daily dispatch problems. For example, batteries may be ramped (from full charge to full discharge) at a high rate during the morning load pick-up and ramped in the opposite direction during the evening load drop-off period. In addition, charging batteries at night can increase night generation levels and reducing daily cycling constraints.

Batteries may only require one to two hours of storage to relieve unit ramping constraints during morning pick-up and evening drop-off periods. However, several hours of energy storage are required to relieve daily generation unit cycling constraints.

Presently, OPC purchases a part of its power needs from other utilities. This permits OPC to schedule its resources and purchases according to its needs. Thus, there are no obvious daily dispatch problems such as ramping or minimum load dispatch.

Area and frequency regulation is another potential battery benefit. Battery power can be quickly and smoothly changed from full charge to full discharge under control of an automatic generation control (AGC) or load frequency control (LFC) system. A battery is thus an ideal device to perform the area regulation function. A battery can also relieve the need to operate costly generation capacity at less than optimum loadings. Another benefit is reduced thermal stress on generating units responding to load variations. There is no appreciable loss of life in a battery due to rapid changes in power.

Batteries would be expected to continuously shuttle between charging and discharging modes on a minute-to-minute basis to perform this area regulation function. Hence batteries used only for area regulation would need only modest MWh storage capability. Also, batteries used for other purposes such as spinning reserve and load leveling could probably simultaneously provide some area regulation service.

The Southern Company area including OPC is dispatched as one area. Thus, the area control area (ACE) for this large system may be in the range of 0-50 MW. Thus, a battery storage system should be rated nearly 50 MW or higher to make significant economic contribution to the area regulation function. In addition, the location of this battery storage system should be easily accessible for dispatch by systems operations control center.

In conclusion, other generation related benefits are not significant within the OPC system at the present time.

6.0 POTENTIAL TRANSMISSION BENEFITS

Battery storage systems, connected at advantageous locations to a transmission system, can provide many benefits as discussed in Appendix A. Some or all of these benefits may be applicable to a given system based on actual system conditions. An evaluation of transmission benefits applicable to the OPC transmission system has been performed. Some background and the results of this evaluation are presented below.

6.1 Background on Battery T&D Benefits

A fair evaluation of T&D benefits of battery energy storage requires recognition that Batteries do not fit conventional, deterministic, T&D planning criteria well. An open mind is needed to recognize where a battery can be advantageously applied. There are definite situations where a battery is most likely to successfully displace other equipment. Some or all of the following conditions are needed for a battery to accrue significant T&D benefits:

- The battery can be located close to customers so that benefits at several upstream voltage levels can be realized,
- The substation or feeder load shape is not very flat so that:
  - The daily low-load period is low enough for the battery to be recharged with a line or transformer out of service,
  - The peak duration is a few hours or less so that a large Mwh capacity is not required,
- Right-of-Way (ROW) is costly or simply unavailable,
- Lines are long or heavily loaded so that losses are high,
- Voltage regulation is a problem so reducing feeder load or providing voltage support is useful,

- Lines are long, radial or highly exposed so that reliability is low,
- Special customer reliability needs exist,
- Blackstart or standby power is needed for a limited amount of customer load, and
- There is space available for the battery.

Where enough of these conditions are encouraging, a preliminary evaluation is warranted. If T&D planning studies to meet the expected load growth are complete, then the analysis is straight-forward. It includes several steps:

- determine the expected load level on the day in which the T&D additions are expected to be in place,
- select a battery Kw and Kwh rating that will defer that load level for a small integer number of years,
- calculate the economic value of deferring the T&D addition for that number of years.
- Repeat for larger integer numbers of years, taking into account these possible limitations:
    - if a transformer is to be deferred, flattening the load shape with a battery may not reduce transformer effective loading in proportion to the reduction in the load peak (where transformers are routinely overloaded during contingencies, maximum load is dictated by the load profile).
    - load must be below equipment ratings at night long enough to allow full recharge of the battery.

6.2 Transmission System Reliability Criteria

The need for new transmission facilities will be generally determined by OPC transmission planning engineers on a case by case basis, based on the evaluation of a number of appropriate design contingencies. The objective of these transmission planning studies is to provide a reliable system considering appropriate outage criteria, risks and costs. The OPC transmission system is normally designed to meet or exceed the following basic reliability criteria.

The basic transmission system reliability criteria for circuits 115 kV and above consists of designing for a single contingency outage during the annual system peak. The basic transmission system voltage criteria is to maintain voltages above 95% of nominal during normal operating conditions and above 90% of nominal during a *single* contingency event.

6.3 New Transmission Projects

In general, the primary purpose of OPC's bulk power transmission system is to reliably deliver power from local and remote generating units to the EMCs. Future transmission systems must provide adequate capability to accommodate expected power purchases from remote generation sources, accommodate new generation projects, and to deliver that power to EMC substations. New transmission additions are a function of both the generation or resource expansion plan adopted by OPC and the need to provide reliable service to areas of high load growth.

OPC keeps a current Project Development Plan that is updated monthly. A recent plan was furnished to PTI. Based on this information, a short list (Table 6.1) of future transmission and substation projects was prepared. Procedures used to make this list are:

-- All released projects are considered to have begun and cannot be substituted with, or deferred by, battery storage systems.

-- Only future projects with the expected starting date of January 1993 or later can be considered to be candidates for possible cancellation or postponement.

TABLE 6.1

OGLETHORPE BATTERY STORAGE STUDY
TRANSMISSION LINES/SUBSTAIONS PROJECTS LIST

SUB NAME	FORECAST PE #	TRANSFORMER MVA	VOLTAGE	PROJECT BUDGET	PROJECT START	REASON
1. S.GRIFFIN FORSYTH	8193	280	230/115KV	$9,100,000	1998	CONTINGENCY OVERLOAD & LOAD GROWTH
2. LLOYD-SHOALS S.GRIFFIN	8193	30.28	Re-Conductor	$2,700,000	1993	OVERLOADING
3. SUWANEE	7992	280	230/115KV	$7,735,000	1994	GROWTH & 115KV LINE LOADINGS
4. VIDALIA	8183	140	230/115KV	$3,620,000	1997	CONTINGENCY OVERLOAD
5. HINESVILLE	8057	280		$3,284,000	1995	OVERLOADING
6. WARRENTON	8060	140	230/115KV	$1,835,000	1996	CONTINGENCY OVERLOAD & LOAD GROWTH
7. LAFAYETTE	8250	280	230/115KV	$1,781,000	1996	CONTINGENCY OVERLOAD
8. LINDALE		22.4 10.5	115/25KV 25/12KV		1992	
9. PEOPLES VALLEY	8257	22.4 10.5	115/25KV 25/12KV	$1,350,000	1995	LOAD GROWTH
10. SLAPPEY DR.		280			1993	
11. N.JEFFERSON	7997	22.4		$274,000	1993	LOAD GROWTH
12. KETTLE CRK	8311	280	230/115KV		1993	

For generic assessment of representative cases, judiciously placed batteries are *considered* to provide a local power source near loads that can act as backup to existing transmission facilities and thereby reduce the transmission redundancy required to meet OPC transmission reliability criteria. The batteries are, effectively, floating on the system, but are used to cover transmission outages. For this application, judiciously placed batteries may provide the desired transmission deferral benefit while at the same time providing additional non site-specific generation system benefits. Based on the 12 projects listed in Table 6.1, OPC selected two specific transformer projects for further study. The results for these two candidates for deferral are presented in this section.

6.3.1 Vidalia 230/115 kV Project

This project consists of installing a third 140 MVA, 230/115 kV transformer at Vidalia substation. According to the present forecast, upon loss of one of the existing two transformers, the remaining transformer will be overloaded after the year 1997. Installation of the third transformer at a budgeted cost of $3,620,000 is being planned for the year 1997.

The 230 kV and 115 kV transmission lines connected to Vidalia substation are shown in Figure 6.1. The installation of a third transformer is being planned as a backup to cover an outage of the existing transformer, as per the deterministic planning criteria.

The overloading of the second transformer occurs only during peak load conditions and if an outage of a transformer occurs. If an alternative method of supplying the local load during this peak and outage period is possible, then the overloading of the remaining transformer can be avoided and hence the installation of the additional transformer can be postponed. Even though transformers are highly reliable, any failure takes weeks to months to repair and bring them back to service. Thus, batteries should be sized so that they are suitable to supply the peak load of the peak day of the year. The peak day load shape for Vidalia substation is shown in Figure 6.2. Both the native load shape and load shape with battery discharge are shown in this figure. Maximum possible peak shaving load, with charging and discharging are included in this evaluation.

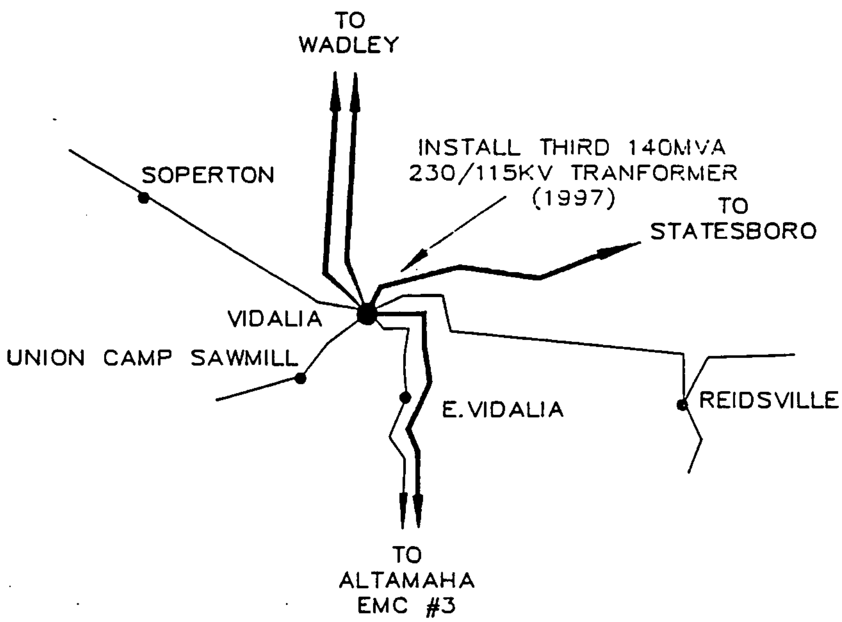


FIGURE 6.1

VIDALIA 230/115 KV PROJECT

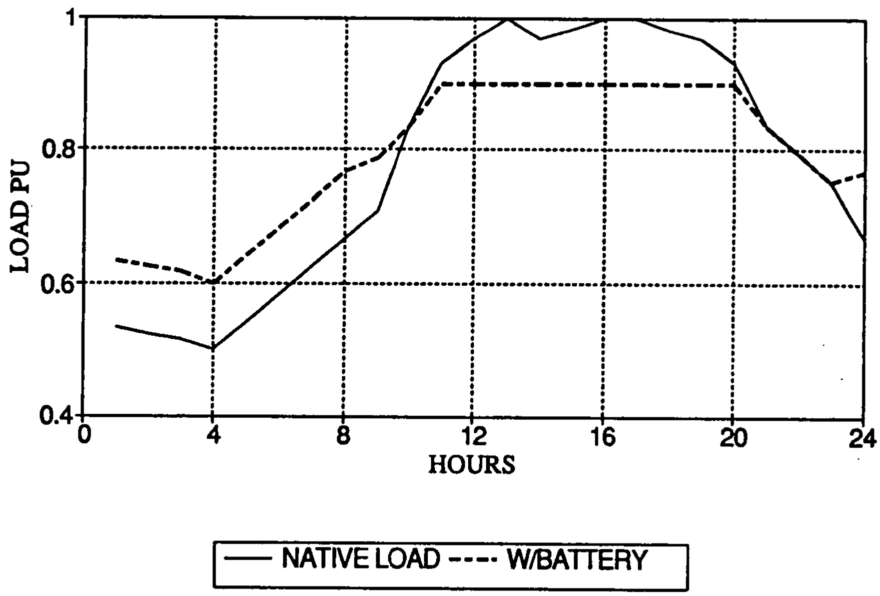


FIGURE 6.2

PEAK LOAD SHAPE - VIDALIA 230/115 KV TRANSFORMER

A number of load flows with outages of Vidalia 230/115 kV transformer and the 230 kV and 115 kV lines connected to the Vidalia substation were run for the year 2001. These load flows showed that in the year 2001 the remaining transformer will be loaded to nearly 110% (156 MW) of its rating. Based on this information and the peak load curve of Figure 6.2, the battery storage requirement is determined. The required battery ratings are as shown in Table 6.2. According to this table a 114 MWH, 7 hour discharge rated battery is needed. The battery size required to meet load growth beyond year 2001 is impractical. As can be seen from Figure 6.2, there are not sufficient charge hours unless a larger KW rating converter is used with the battery. Adding the third transformer may be postponed for only 3 years with the proposed size of the battery. The battery may be placed on the 12 kV bus of the Vidalia substation, thus deferring some distribution transformer additions also.

TABLE 6.2

VIDALIA BATTERY RATING REQUIREMENTS
ONE TRANSFORMER CAPACITY = 140,000 KVA

YEAR	1998	1999	2000	2001
Transformer Overloading KVA	0	1,019	9,048	17,494
Peak Load kW	133,919	140,938	148,324	156,098
Battery KW	0	938	8,324	16,098
Battery Power (pu)	0.00	0.01	0.06	0.10
Battery KWH	0	4,228	51,419	114,472
Battery Hrs	0	5	6	7

Because the 230 kV and 115 kV transmission lines parallel each other, the battery output will reduce only a part of the load on the 230/115 kV transformer. Through load flows it was determined that 53% reduction in the transformer and 47% reduction in 115 kV lines occurs for every MW of battery output. Thus, the battery requirements in Table 6.2 need to be increased by 1.8. Hence, a battery rated at 210 MWH, 7 hours discharge can defer the installation of transformer from presently planned 1997 to year 2001.

6.3.2 Warrenton 230/115 kV Project

This project involves several new construction parts. The main part is installation of a second 140 MVA, 230/115 kV autotransformer at the Warrenton station. The basis for the second transformer is that the loss of Evans-Warrenton 230 kV line will force the power through the Warrenton 230/115 kV transformer and causes overloading of the only transformer. The total projected capital cost of this project is 4.7 million dollars out of which the second transformer costs $1,835,000 in 1991 dollars.

The 230 kV and 115 kV lines connected to Warrenton substation are shown in Figure 6.3. The second transformer is being planned to meet the deterministic planning criteria, that upon outage of Evans-Warrenton 230 kV line the Warrenton 230/115 kV transformer should not be overloaded. The line outage could occur on a peak day during peak period. Hence the battery (which is expected to reduce or eliminate the overload) should be properly sized so that both discharging and charging can be made within a 24 hour period so that the battery is available for the next day peak period. Based on this premise, the peak day load shape, with and without the battery, is shown in Figure 6.4. All the charging and discharging limitations are observed in plotting the modified (shown dotted) load shape.

The battery rating requirements are shown in Table 6.3. These are based on peak load forecast and the peakday load shape (Figure 6.4). For example, also shown in Table 6.3 for the year 2001, a battery of 33 MWH storage capacity with a maximum discharge rating of 10 MW is needed. However, there is another consideration in selecting the battery. As shown in Figure 6.3, the 115 kV transmission lines parallel the 230 kV transmission lines. Hence, out of every MW of battery discharge, only part of this load relief goes to the 230/115 kV transformer. By using load flow runs, it was determined that for every 10 MW battery discharge at the 115 kV side of the transformer, only 3.6 MVA or 36% relief in loading is obtained for the 230/115 kV transformer. Hence, the battery ratings need to be multiplied by a factor of 2.8 (= 1/3.6) to get the desired relief or divided by a factor of 2.8 to determine actual relief from a given battery size. Thus, the final battery ratings selected for evaluation is 218,000 KWH with 5 hour discharge rating.

TABLE 6.3

WARRENTON BATTERY RATING REQUIREMENTS
ONE TRANSFORMER CAPACITY = 140,000 KVA

YEAR	1997	1998	1999	2000	2001	2002	2003	2004
Transf. Overloading KVA	3,513	5,333	7,174	9.036	10,920	12,826	14,754	16,705
Peak Load kW	143,232	144,906	146,600	148,313	150,046	151,800	153,574	155,369
Battery KW	3,232	4,906	6,600	8,313	10,046	11,800	13,574	15,369
Battery Power (pu)	0.02	0.03	0.06	0.06	0.07	0.08	0.09	0.10
Battery KWH	3,683	6,831	16,754	23,730	33,010	43,805	58,358	77,684
Battery Hrs	2	2	3	3	4	4	5	5

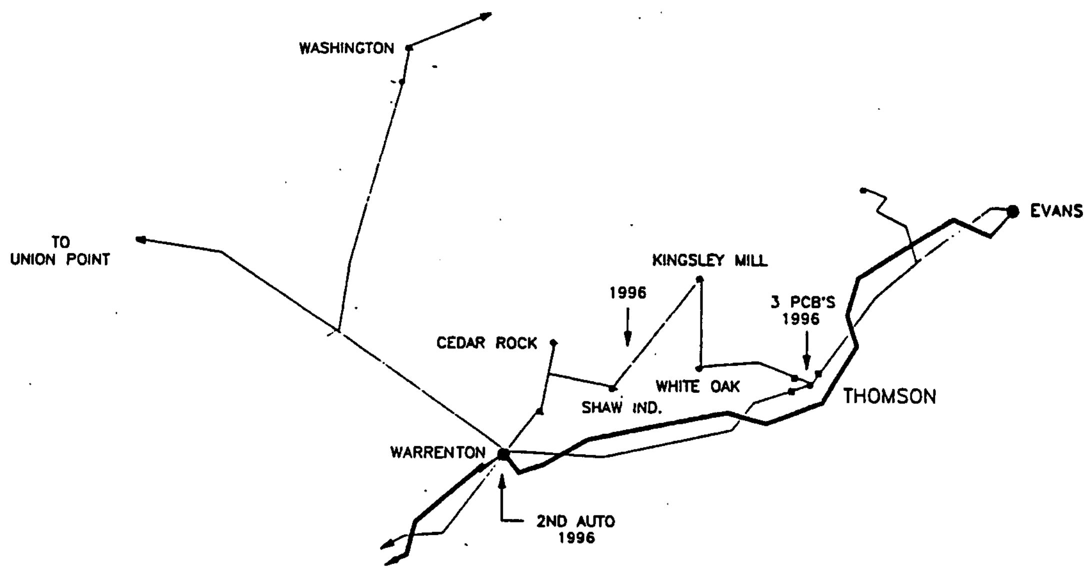


FIGURE 6.3

WARRENTON-THOMSON 115 KV PROJECT

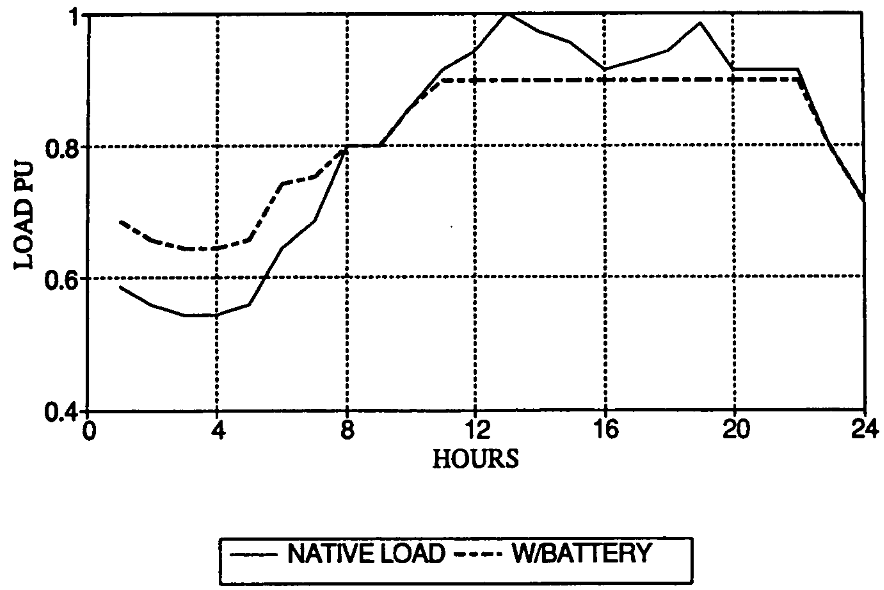


FIGURE 6.4

PEAKDAY LOAD SHAPE - WARRENTON 230/115 KV TRANSFORMER

6.4 Loss Reduction

Batteries can reduce transmission losses by shifting load from the peak period to the off-peak period. This results from the square law that governs resistive losses. Reducing transmission system loading during daily peak load times by discharging batteries reduces peak load losses by more than they are increased at night when the batteries are recharged.

The potential loss reduction benefit is reduced if batteries are used to defer transmission. When transmission is deferred, it is possible for a high penetration of batteries to actually increase losses and incur a negative benefit. This can occur if the load shape is greatly flattened by batteries, so that average transmission loading is very high. The levels of battery penetration that are likely to be attractive in the foreseeable future will reduce losses.

If the proposed application requires the battery to be cycled frequently, consideration of losses will be more important than in applications where the batteries are to be cycled only occasionally, or where only small amounts of energy are involved. Of course, if the loss benefits themselves are significant, they should be a factor in determining the frequency of cycling.

The location of the generation used to charge the batteries and the location of the generation displaced when the batteries are discharged will each have a significant impact on the relative magnitude of the peak and off-peak losses and the loss benefit.

The daily load shape on the local transmission system in the vicinity of the battery may not coincide with the native daily OPC load shape. When there is a difference, the battery cannot provide maximum loss reduction throughout the network. If the battery discharge pattern is dictated by resource consideration associated with the system-wide peak, and the local peak does not coincide with it, the local loss reduction will be modest. So long as the local substation or feeder peak falls within the system native load peak, loss reduction will be high.

In battery storage applications where transmission loss benefits are to be determined, the best available marginal generation costs and corresponding marginal loss factors should be determined. Although the daily load shapes fluctuate significantly, the hourly marginal generation costs are relatively constant on a daily on-peak/off-peak basis for the different seasons. Thus, on the OPC system, relative cost of transmission losses may be quickly estimated using incremental on-peak/off-peak transmission loss calculations, without resorting to hourly production simulation.

The two previously discussed battery applications for deferment of 230/115 kV transformers would actually be used only after contingency. Thus, the number of hours that the battery would be used in a year is small. Hence, any change in losses in the transmission system is considered insignificant for the two cases evaluated here.

6.5 Voltage Regulation

Regulation is the drop in voltage that occurs when load increases on the system. The larger the voltage change, the poorer the regulation. For the same level of load, when system impedance is high (the system is weak), regulation will be poor. Adding lines and transformers can strengthen the system, but are a costly way to solve poor voltage regulation problems. Conventional voltage control devices such as generators, synchronous condensers, switched capacitor banks, static var systems (SVS), and load tap changers on transformers 'regulate' voltage and improve regulation. The voltage regulation response times for the various voltage control devices are:

LTC	1 to 2 minutes
Capacitors	1 to 2 minutes
Generators	1 to 2 seconds
Condenser	1 to 2 seconds
SVS	0.1 to 0.2 seconds

The SVS is clearly the most effective because of its speed. An SVS consists of some combination of thyristor switched shunt capacitors and thyristor controlled shunt reactors. An SVS can respond to a drop in voltage before it becomes a problem for voltage-sensitive equipment or before a person can see the voltage drop in the light output of fixtures. Generators are often located too far from the load to be useful. Synchronous condensers are no longer competitive compared to SVS. LTCs and switched capacitors are slow, but are economical and very effective at combating slow changes in voltage, such as those resulting from normal load variations.

Judiciously placed batteries can improve voltage regulation in two ways. One is by supplying power locally when heavy transmission loading or transmission outages are the cause of the low voltage. Increasing battery power to reduce line loading will improve voltage. Each MW of battery power is equivalent to 2 to 3 Mvar of reactive power in terms of its impact on voltage in heavily loaded systems.

Batteries can also improve voltage regulation through reactive supply from their gate-turn-off (GTO) or similar power converters. The converters between the ac system and the battery dc bus can be designed to behave like an SVS while charging or discharging the battery. A modest increase in converter rating, over that required to supply full battery power, is necessary to supply reactive power during charging or discharging operation. For example, an 11 MVA converter on a 10 MW battery can provide up to 4.6 Mvar of capacitive or inductive reactive power while operating at 10 MW. The reactive power is also continuously variable and controllable with a voltage regulator. The extra 1 MVA of converter capacity thus provides the same dynamic range as a 9.2 MVAR SVS. Because most SVSs provide primarily capacitive reactive power, a 4.6 Mvar capacitor is required to make the converter fully comparable to an SVS. However, even with the cost of the capacitor, and recognizing that GTO based converters are more costly (per MVA) than thyristor based SVS, the battery converter is a very economical alternative to SVS capacity.

There were no specific and imminent shunt capacitor or SVS installation projects selected for the analysis. However, there is potential for battery storage to defer T&D projects as well as eliminate shunt capacitor by supplying reactive power. Hence, a generic example is shown here to illustrate computation of voltage benefits from voltage regulation capability of batteries.

Consider a 10 MW battery with additional 1 Mvar of converter capacity. This is equivalent to 4.6 Mvar of switched shunt capacitors or 9.2 Mvar of SVS capacity.

The installed cost for new conventional capacitor banks at the transmission voltage level may be about $33.00/kvar. SVS is estimated to cost three times as much or about $100/kvar. Both numbers are reasonable, though some utilities are finding actual costs of conventional capacitor banks to be up to 50% higher where land costs are high. The $100/kvar number for SVS is for relatively large SVS. Costs can be much higher for smaller size SVS.

A 10 MW battery is likely to have a converter cost of about $150/kVA if utility battery volume picks up (today the number is $200/kVA). Assuming that the incremental cost of converter capacity is 2/3 of this overall $/kVA cost, an incremental kVA would cost about $100. As described above, adding an additional MVA of converter capacity will provide 4.6 Mvar of capacitive reactive power (more at reduced MW output) at a cost of about $100,000 (Appendix B). The cost of 4,600 kvar from a 10 MW battery converter is thus about $22 per kvar. Cost comparison of battery converter, shunt capacitor and SVS is shown in Table 6.4. The battery converter thus appears economically competitive ($20.00/kvar savings) with switched shunt capacitors installed at the transmission level.

TABLE 6.4
COST COMPARISON OF BATTERY CONVERTER, SHUNT CAPACITOR & SVS

Type	Cost ($/KVAR)	Size (KVAR)	Capital Cost	Total Net PV	Net PV ($/KVA)
Shunt Capacitor	33	4,600	$151,800	265,551	58
Battery Converter	22	4,600	$101,200	177,034	38
SVS	100	9,200	$920,000	1,609,401	175

Note: (a) Economic Parameters as in Table 8.1
(b) PV - Present Value

6.6 Damping

Batteries are especially adept at providing system damping. Batteries can respond instantaneously to control signals with no measurable wear and tear. The control signal to improve system damping can be derived from the frequency of the voltage at the battery terminals. The only limitation is that the battery must be within the 'sending' or 'receiving' system to provide damping.

6.6.1 Background

Power systems are like large spring-mass systems. The generator and turbine rotors are the masses, and the network is the spring. Every generator and every group of generators will have a natural frequency at which it will oscillate against the remainder of the network when perturbed. These natural frequencies are usually in the range of 0.2 to 2 Hz. Unfortunately, there is 'noise' in the system such as customers switching loads, pulsating loads, generator trips, line faults and line trips that excite these oscillations. At oscillation frequencies above about 1 Hz "amortisseur torques" in the generator usually provide enough damping to cause oscillations to decay quickly (within 5 to 10 seconds). However, below 1 Hz excitation systems may provide enough negative damping to overcome damping from amortisseurs and cause oscillations to grow. This is especially likely when a system is stressed by high transfers or loss of a line. Fast response excitation systems, or newer static systems that inherently provide fast response, are much more prone to cause negative damping than standard designs. They are often installed as replacements for older ailing or high maintenance systems, on utility generators to solve first-swing stability problems, or on QF, IPP and cogeneration plants because of low maintenance and modest first-cost.

If negative damping from excitation systems exceeds positive damping from amortisseurs at any natural frequency under any system condition (e.g., during line outages), oscillations will occur. Governors, turbines, and customer loads also affect damping somewhat, especially when the natural frequency is below about 0.5 Hz. Oscillations may grow without bound until loss of synchronism occurs or they may reach some magnitude and stay at that level for an extended period of time. Both consequences are unacceptable.

To help combat the problem of poor or negative damping, stabilizers are placed on the excitation systems of larger generators. Stabilizers modulate excitation so as to produce a component of generator power that is in phase with generator speed, and thus provide damping. Stabilizer effectiveness depends on the response characteristics of the excitation system. A well tuned stabilizer will usually overcome the negative damping caused by the excitation system on which it is installed. It will help compensate for other generators without stabilizers only if the excitation system on which it is located is of the "high initial response" type and has a relatively high ceiling voltage. A stabilizer can provide a component of positive damping power from about 1% to 5% of the generator rating, depending on the excitation system performance.

Excitation systems contribute more negative damping as power transfers increase, but first-swing stability, steady state stability and thermal limits also come into play. However, multiple interconnections have made first-swing and thermal limits less limiting than damping in many systems. This occurs in part because multiple interconnections allow each line to be loaded more heavily, and heavy loading, through high reactive losses, causes excitation systems to contribute more negative damping.

Damping problems commonly fall into two categories. One is oscillations between a single plant and the remainder of the system. Usually, loss of one of the lines serving the plant puts the plant in an unstable condition. The other is oscillations between groups of machines. Oscillations between groups of machines are usually labeled as 'area' or 'regional' damping problems. The oscillations involving a single plant are usually in the 0.8 to 1.3 Hz range, while area or regional oscillations are usually in the 0.2 to 0.8 Hz range.

6.6.2 Damping in the Oglethorpe System

In planning and operating the Oglethorpe system the engineers must deal with both single plant damping and area or regional damping. The Sherer plant is a good example of the single plant damping problem. Until recently, there were just two 500 kV lines serving the plant, so loss of either one significantly increases the impedance between the plant and the system and degraded damping. With the recent addition of the Ohara-Sherer 500 kV line there may still be a damping (or dynamic stability) problem. Computer results are showing inter-area (i.e. Alabama-Georgia, Georgia-Florida, etc.) oscillations at 0.7 Hertz due to faults at Sherer. The Power System Stabilizer (PSS) at Votgle was placed in-service, and the PSS for Farley units #1-2 were retuned to provide more positive damping. It is also possible that generators on other surrounding systems may contribute to the damping problem. The system data and outside equivalents are being reviewed. Consideration is being given to making the outside equivalents larger which may help the problem.

Though system study models rarely portray the damping of such modes accurately, they do confirm their existence. Also, the fact that they exist and can be troublesome is well recognized throughout the US.

6.6.3 Battery Contribution to Damping

While stabilizers are usually able to control oscillations, increasing numbers of aggressively tuned stabilizers are required as transfers increase. Having enough stabilizers and keeping enough of them operating to keep oscillations under control is difficult. Stabilizers are costly and are a fairly high maintenance item. Hence any help from batteries would be very useful, especially if the stabilizer can be a simple device integrated with the battery controls.

Batteries can contribute to damping if they are equipped with a stabilizer and if they are located in a portion of the system in which generators experience measurable rotor speed oscillations when plant or inter-area oscillations occur. Such rotor speed oscillations exist at the extremes of two oscillating areas, and are zero at the 'electrical center' of the two. The oscillations will also be largest in the smaller of the two systems (the magnitude of the oscillation is inversely proportional to the inertia of the area or plant). In the case of a single generating plant oscillating against the 'outside world,' the oscillations at the plant will be large, while the 'world' oscillations will be very small. In the case of two areas such as Florida oscillating against the remainder of the Southeast, the Florida oscillations will be large and the oscillations in the remainder of the Southeast will be small.

A generator stabilizer provides damping by increasing generator rotor flux when generator speed is high to increase generator power, and decreasing flux to reduce generator power when speed is low. A battery nearby provides damping by being modulated so that it absorbs power when the speed of local generators is high and supplies power when the speed of local generators is low. Because the frequency of the voltage in an area follows closely the speed of local generators, the system frequency at the battery location provides the information needed to modulate the battery power.

The battery thus needs to be near a plant or group of generators in a 'sending system' or within the receiving system. It also will be most effective if it is in the smaller of the two oscillating areas.

The battery power can be modulated to provide damping regardless of the power level or direction of power level in the battery at the time the oscillations occur. If the battery is floating, the output will alternate between the charge and discharge regions, and average battery output will remain zero. If the battery is operating at a high charge or discharge level, the average power will move toward zero. If oscillations are large, the average may go to zero as the stabilizer causes battery power to cycle between its charge and discharge limits.

Because a stabilizer on a generator can provide damping power of just a few percent of generator rating, a battery of, for instance, 2 MW, modulated fully (4 MW peak to peak), can provide as much damping as a stabilizer on a generator rated 100 to 200 MVA. Beyond this, because a battery is essentially solid state and less subject to control oscillations than a generator, the stabilizer gain can be high and can contribute more to damping of modest oscillations (that would otherwise not drive the battery to ceiling) than can a generator stabilizer.

While the stabilizer is responding to a disturbance it will reduce average battery power when the battery is initially operating at maximum discharge rate. The effect will be less at lower discharge levels, and nonexistent when the battery is floating (operating at zero MW). Likewise, there will be a momentary reduction in the charge rate when the battery is initially operating in the charge region. This occurs when the stabilizer drives the battery between its maximum discharge and charge limits. With battery output essentially a square wave, the average power is zero. This effect is essential if the battery is to make a major contribution to damping under all battery operating conditions. Because the change in battery power or charge level is temporary, lasting only 10 to 30 seconds or less, it should not present operating problems.

6.6.4 Battery Contribution to Damping on the Oglethorpe System

In a system such as that covering Georgia, with generating plants distributed across the system, batteries will provide useful damping wherever they are located. However, the value will be low unless the battery is located with or close to a generator or group of generators that exhibit troublesome oscillations.

The oscillations between Georgia and Florida exhibit large oscillations only in Florida. Hence a battery in Georgia will contribute little to this mode. Any troublesome mode within Georgia is not readily available.

7.0 POTENTIAL SUBTRANSMISSION AND DISTRIBUTION SYSTEM BENEFITS

7.1 Subtransmission System

The subtransmission system (less than 115 kV) within the OPC delivers power to the EMC substations. The EMCs have the responsibility to deliver the power from these substations to the ultimate customer. The subtransmission lines and/or distribution lines serving the EMC substations include 115 kV, 69 kV, 46 kV, 25 kV and 12 kV lines.

In the OPC system there are approximately twenty-four 115 kV and 46 kV subtransmission lines which are radial and supply EMC substations. Whenever there is an outage of one of these radial subtransmission lines, the customer loads experience an interruption. Batteries located at the low side of these substations can provide multiple benefits, including:

- increased reliability (back up power source)
- second line deferral benefits
- transformer deferral benefits
- voltage regulation
- reduction of losses

7.2 Backup Source Reliability Credit for Battery Storage

A battery is a 'local source' and thus is not dependent on upstream components as are, for instance, the transmission or distribution lines. The battery is, in effect, an independent source of power (temporary or backup) and thus may make a more significant contribution to reliability than its outage rate and duration statistics would seem to indicate. It is an independent source because it is not part of a series string of devices, and one of which can cause an outage or reduced capacity. However, the benefit a battery can provide as a backup source depends upon three factors:

1. Battery availability and reliability
2. Outage or interruption of load experience (or expectation)
3. Value or cost of the load interruption.

These three factors are discussed in the following.

7.2.1 Battery Availability

Unlike transformers, transmission and distribution lines, batteries are not necessarily "available" just because they are on-line. Generally, batteries need to be in a charged state, and have a specific energy storage capability to be considered reliable backup to various T&D facilities. A battery that is normally discharged to 20% of capacity can be discharged to 90 or 100% in an emergency. It may be able to supply energy for the time needed for switching actions to restore or re-configure lines and transformers to carry the full substation load, and thus may provide useful backup to T&D equipment.

A probabilistic reliability assessment may be needed to fully recognize a battery's contribution to reliability. Utilities still depend heavily on deterministic criteria, and thus may have difficulty measuring the reliability at a substation load served in part from a battery. The contribution a battery can make in meeting utility distribution reliability criteria has not been analyzed. A simple approach to battery availability will be used here.

7.2.2 Value or Cost of Interruption

The interruption cost or value of service (VOS) data is considered to be suitable to relate the worth of service reliability to the cost of service. The value of service or outage costs depends upon type of load, frequency and duration of interruption and timing of the interruption. However, some of these costs have a wide range. The cost range for one hour interruption has been reported in the literature. A sample of such costs is shown in

Table 7.1. The interruption cost data are reported in the literature for farming type loads.[1] In a parallel study on dispersed generation benefits, a survey of chicken farm owners in the Habersham EMC (Hollywood substation) area was conducted. In this survey it was established that $14.8 per KWH is VOS or outage cost. This same cost will be used for Habersham EMC's poultry and egg farm loads.

Because the EMC customers are predominantly residential type, followed by commercial and industrial, an average residential outage cost of $2.50 per KWH will be used for transmission level deferral application.

TABLE 7.1

VALUE OF SERVICE OR OUTAGE COST FOR ONE HOUR INTERRUPTION

	$/KWH Not Served	
	Low	High
Residential[2]	0.05	5.00
Industrial[2]	2.00	53.00
Commercial[2]	2.00	35.00
Poultry & Eggs[1]	0.12	5.68

7.3 Habersham Hollywood Metering Point #8 Substation

This metering point is served by two 115 kV lines from Tallulah and Clarksville. There is one 115/12 kV; 10,500 KVA transformer at this substation. At present, there are five, three-phase 12 kV circuits emanating from this substation. Circuits #1 and #2 serve the area

[1] G. Walker and R. Billinton, "Farm Losses Resulting from Electric Service Interruptions - A Canadian Survey," IEEE Transactions on Power Systems, Vol. 4, No. 2, May 1989, pp 472-478.

[2] A.P. Sanghvi et al, "Power System Reliability Planning Practices in North America", IEEE Transactions on Power Systems, Vol. 6, No. 4, Nov. 1991, pp 1485-1492.

generally north of the substation. Circuit #3 serves the area generally east and southeast of the metering point. This circuit has a TV station load and a county water pump house load. A battery of suitable size located near these loads can provide improved reliability to these large power loads. Circuit #4 serves the area generally west of the metering point. Circuit #5 serves the area generally to the northwest of the substation. This feeder (New Liberty) has the highest number of chicken farms. Power supply interruption to these chicken farm loads can result in substantial loss to their owners. Hence, there is an active consideration of using diesel generators as backup power source. The feasibility and economics of diesel generators are being evaluated through a separate study. The role of batteries for providing the backup service and deferment of distribution facilities is evaluated in this study.

7.3.1 Deferment of Substation Transformer Replacement

Load on this circuit (area) is expected to grow at a rate of about 3.4% per year. The existing transformer of 10,500 kVA can serve the load up to year 1998. By then a replacement or an addition is required. If batteries are installed at the substation or near the loads, the batteries can be used to peak shave the loads whenever the total coincident load exceeds the transformer capacity. A typical peak day charge/discharge load profile is shown in Figure 7.1. The battery rating required to defer the addition and/or replace the transformer is shown in Table 7.2. The selected battery is 7,500 KW and 5 hours discharge rating.

TABLE 7.2

HABERSHAM HOLLYWOOD METERING POINT #8
BATTERY RATING REQUIREMENTS
EXISTING TRANSFORMER CAPACITY 10,500 KVA

YEAR	1999	2000	2001	2002	2003
Forecast Peak Load kW	9,837	10,171	10,517	10,874	11,244
Battery KW	177	511	857	1,214	1,584
Battery KWH	327	1,105	2,387	4,094	6,658
Battery Hrs	2	3	3	4	5
Cycles/Yr	1	8	10	12	32

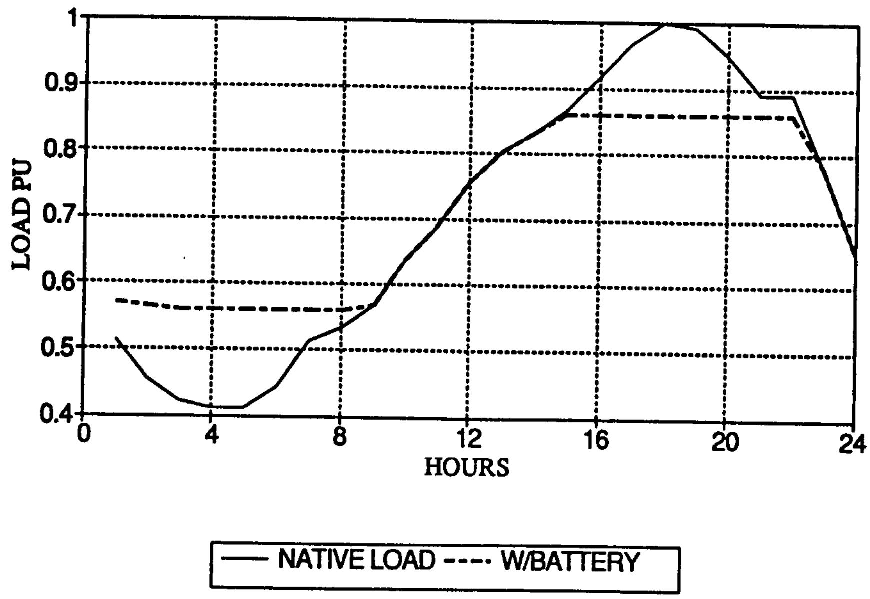


FIGURE 7.1

SUMMER PEAKDAY LOAD SHAPE - HABERSHAM #8 HOLLYWOOD SUBSTATION

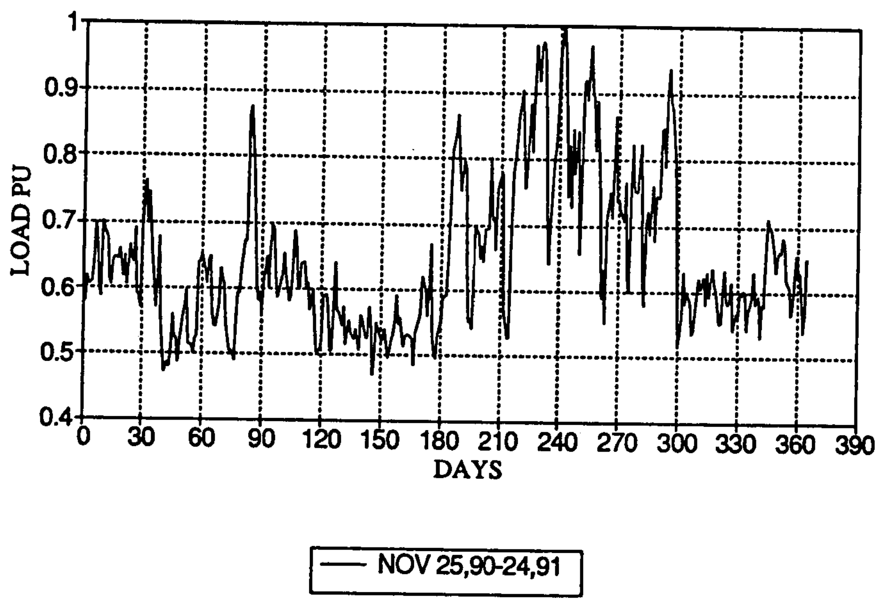


FIGURE 7.2

DAILY PEAK LOAD - HABERSHAM HOLLYWOOD SUBSTATION

Based on the values in Table 7.1, a maximum of 1500 kW of load growth for this area can be served without replacing the existing transformer or adding another transformer. Because the peak load is experienced only a few times in a year (Figure 7.2), the battery is called on to discharge only these few instances. As shown in Table 7.1, the load on the transformer in the early years is exceeded only a few times a year and increased as the load growth occurs. By the year 2003, on 32 days (mostly during the summer), the battery could be used to limit the transformer loading. Also, the battery is expected to be in the discharge mode for about 8 hours. Based on these two factors, it appears that 7500 kWH battery storage is nearly the penetration limit, as far as the transformer deferment is concerned.

Assuming this size of battery application, a transformer addition can be postponed up to 5 years. If the batteries are not installed, then the most likely action would be to add another transformer of 20,500 kW capacity at an estimated cost of $300,000 (1991 dollars).

7.3.2 Losses

Regarding losses on the 115 kV lines, the Hollywood substation load is about 7% of the line flow. Further, battery reduces the peak substation demand by 15% (Table 7.2) in the year 2003. Peak line flow is reduced by about 1% only. After year 2003 the transformer can no longer be deferred. Hence, cost of loss reduction is not significant in this case. If the batteries are located near the loads, rather than in the substation, then there is reduced losses on the 12 kV feeders. Because actual locations are indefinite, the reduction in loss are difficult to compute.

7.3.3 Backup Power Supply Credit

The outage data for Habersham #8, Hollywood distribution substation are as shown in Table 7.3 for the period January 1, 1986 through November 1, 1991. The availability of a battery to serve as backup will depend on alternative functions it may serve.

If a battery is on a single radial feeder, so that the battery must be available to continue serving the load whenever the outage occurs, then the battery must remain fully charged whenever the critical load is on the system.

The longest outage seen at this substation, during the last 5 years, is 21 minutes. The outage experience downstream at the customer premises may be longer. Assuming an outage duration of 1 hour, the value of service credit is estimated to be $14.78/KWH (from survey of Habersham chicken farm customers in another companion EPRI study). At a first glance, this credit may appear to be high. However, a single outage of 1 hour or longer can result in a loss of $300,000 to a chicken farm with a peak load of 500 kVA.

Because there is no demand charge for these chicken farm load customers, there is no demand charge credit to the battery storage.

TABLE 7.3

OUTAGE STATISTICS SUMMARY

	Hollywood	Lanes Bridge	Planters Egypt
No. of Outages in 2130 days	4	4	7
Frequency of Outages (Occ. per yr)	0.685	0.685	1.2
Average Duration (Min.)	11.5	361.5	109.7
Probability of Outage	0.000015	0.00047	0.00025
Longest Outage (Min)	21	1133	267

7.4 Satilla EMC Metering Point #12 Lanes Bridge Substation

This metering point is served by a radial 46 kV line from Baxley Substation. Baxley Substation has three 115 kV lines from three different substations. The outage data for Lanes Bridge Substation for the reported period Jan. 1, 1986 through Nov. 1, 1991 are shown in Table 7.3.

Even though there have been only four outages in nearly 6 years, Lanes Bridge Substation experienced one long outage lasting 6 hours, probably due to an ice storm. Adding a battery at this substation and/or customer locations will provide backup power supply.

7.4.1 Deferment of Substation Transformer

The load on this substation is growing at about 2% per year. At this rate, the existing transformer capacity will exceed its rating of 7000 kVA in the year 1997. Battery energy storage could be used to supply the load whenever the transformer is fully loaded. Transformer per unit loading with and without a battery is shown in Figure 7.3. The battery storage requirements through the years 1997 to 2001 are shown in Table 7.4. The battery use in terms of cycles per year are also shown in this table, based on the relative daily peaks for this substation (Figure 7.4). For example, in the year 2001, the batteries are projected to be used on 47 days to limit the loading on the transformer. Based on these load profiles, a battery storage rating of 9000 kWH and 6 hours will be able to defer adding new or replacing the existing transformer by 5 years.

TABLE 7.4

SATILLA #12 EMC
BATTERY RATING REQUIREMENTS
EXISTING TRANSFORMER CAPACITY 7000 KVA

YEAR	1997	1998	1999	2000	2001
Forecast Peak Load kW	6,840	6,797	7,130	7,480	7,846
Battery KW	40	357	690	1,040	1,406
Battery KWH	92	1,021	2,968	5,042	7,986
Battery Hrs	3	3	5	5	6
Cycles/Yr	1	2	17	33	47
Selected Battery Rating	9000 KWH, 6 Hour battery				

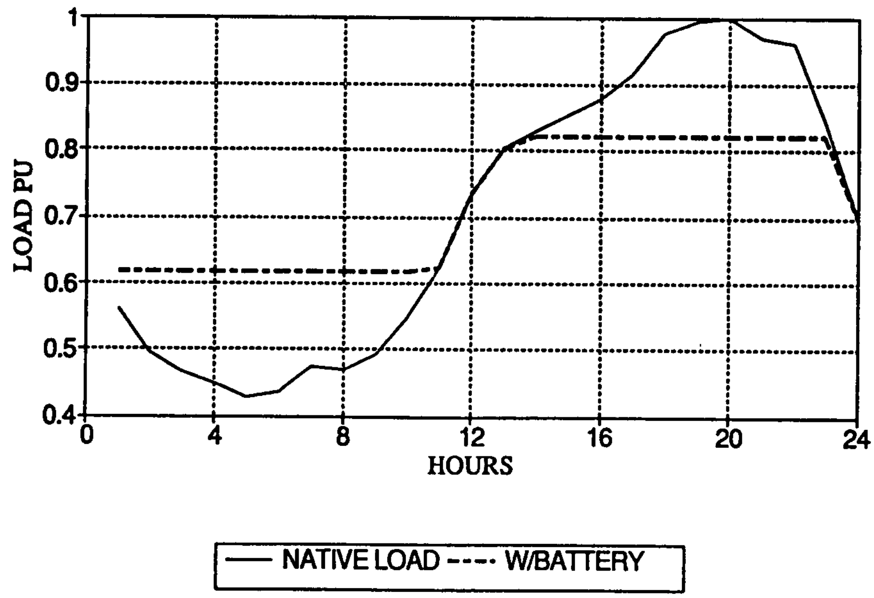


FIGURE 7.3

SUMMER PEAKDAY LOAD SHAPE - SATILLA LANESBRIDGE SUBSTATION

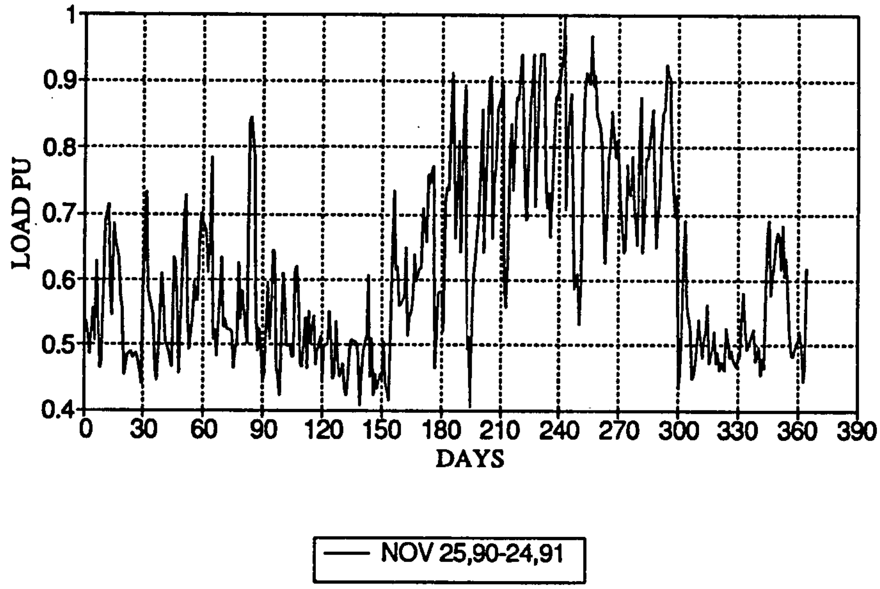


FIGURE 7.4

DAILY PEAK LOAD - SATILLA LANESBRIDGE SUBSTATION

7.5 Planters #9 Egypt Substation

This substation is fed through a long 46 kV radial line traversing swamp area.

Because of swampy terrain, when outages occur, relatively longer time is needed to repair and restore the line back into service. This line has experienced 7 outages in the last 70 months with the longest outage lasting over 4 hours (Table 7.3). The seven outages are almost twice as many as Hollywood Substation. Effort is being made to improve the right-of-way and clearances to reduce the number of outages.

7.5.1 Deferment of 46/12 kV transformer

The load in the Planters #19 Egypt Substation is projected to grow at a rate of about 5% for the first year of this study, 2% for the second year and 1% for subsequent years. The existing 46/12 kV transformer has a capacity of 5250 MVA. The existing transformer is sufficient to serve the projected load up to the year 2005. By then if the batteries are in place, then the transformer addition can be postponed. The summer peak day load shape with and without a battery is shown in Figure 7.5. The daily peaks are shown in Figure 7.6. As can be seen from this figure, the 1991 annual peak occurred in winter. However, the winter peak occurred for only a 4-day period with sharp peaks and low energy content. The summer peak day load shapes are relatively flat and peak energy requirements are higher than the winter peak days. Hence, the battery energy capacity must be determined by using the summer peak day load shape. The number of cycles used per year will be fairly small. Because existing distribution transformer capacity is sufficient for over 10 years; distribution related benefit is considered to be zero.

7.5.2 Another Supply Source

Providing a second feed into the Egypt Substation will reduce the number and duration of outages experienced by customers served by Egypt Substation. Several alternatives are available, namely, upgrading the 46 kV line to 115 kV, adding another 46 kV line or taping a nearby Guyton-Newington 230 kV line (owned by Savannah Electric Power Co.) via a 230/46 kV transformer. Upgrading from 46 kV to 115 kV is the preferred alternative. The estimated cost of this alternative is $5,339,510. This alternative will be used to determine cost savings from deferment due to battery installation.

In order for the battery storage to truly qualify as a substitute second source (in place of a 115 kV line), the battery kW rating should be equal to or greater than the forecast peak load (4841 kW in year 2001 from Table 7.4) and the longest outage experienced in the last 6 years (4 hours and 27 minutes from Table 7.2). A minimum rating of 22,000 kWH and 4 hours rating for the battery will meet these requirements.

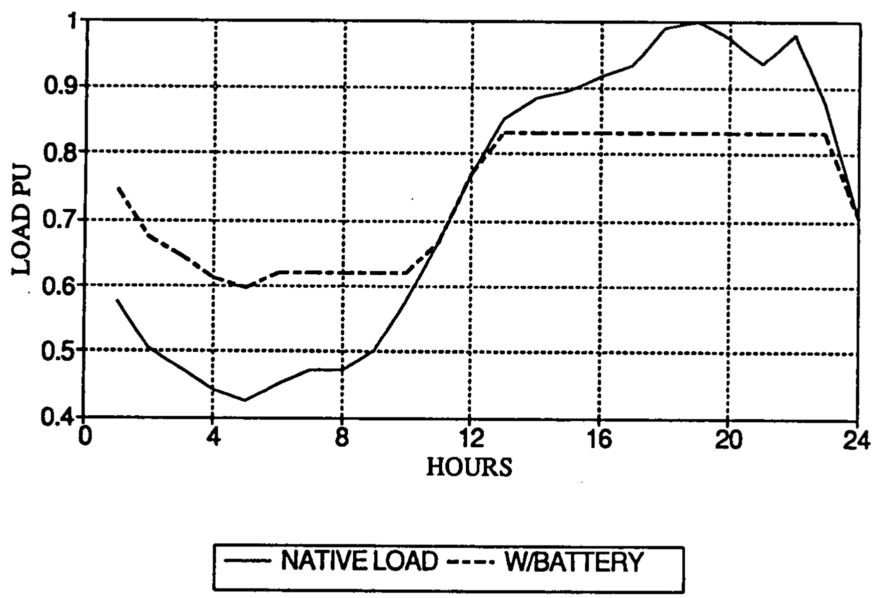


FIGURE 7.5

SUMMER PEAKDAY LOAD SHAPE - PLANTERS #9 EGYPT SUBSTATION

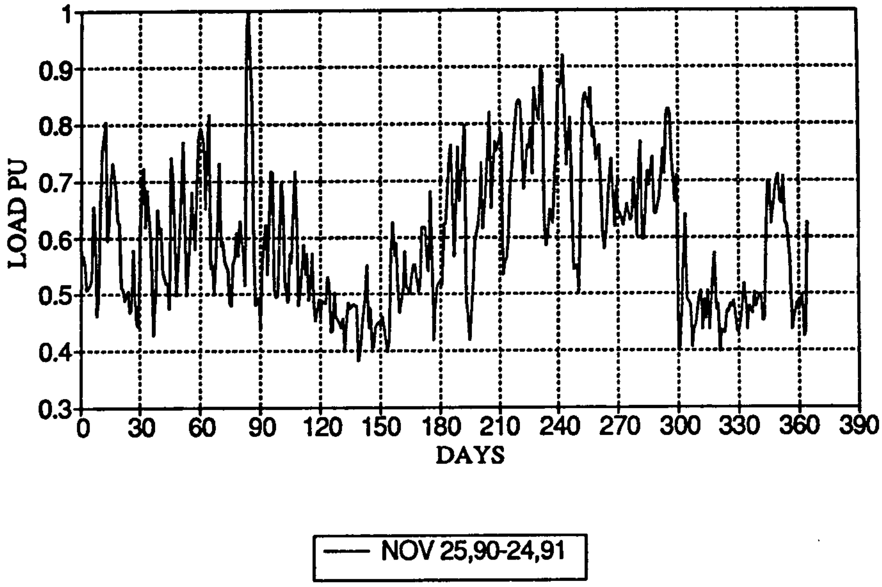


FIGURE 7.6

DAILY PEAK LOAD - PLANTERS #9 EGYPT SUBSTATION

8.0 BENEFITS - COST COMPARISON

The results of a benefit to cost comparison for the five battery storage applications to defer transmission and distribution projects are presented in this section. The methodology used for benefit to cost comparison is essentially based on calculating the present worth of all the annual cost savings/benefits accruing due to the battery application, compared to the annual cost of owning and operating the corresponding battery plant.

Only four major benefits due to battery storage application are considered. They are:

- Generation capacity
- Transmission deferment
- Distribution deferment
- Value of service or cost of outage.

8.1 Basis

The battery storage identified in this study is mostly in the form of a backup or reserve source. It is not used in the general sense of load leveling. As stated in the end of Section 5.1, a generation capacity (KW) credit based on a 10 hour discharge rating is applicable. The battery KW (based on 10 hour discharge rating) is essentially a generation reserve source. This may not be needed at the peak load condition. However, if a probabilistic generation reliability criteria (such as loss of load expectation - LOLE), is used, most of the contribution to the LOLE is during the peak load months. Hence a 10 hour discharge rating is used so that even if this reserve is called upon during the annual peak load condition, the battery will be in a position to provide the power (KW) equal to the credit it has received for the longest peak load period of 10 hours. Thus, for example, a 10 MW, 1 hour battery will be given a credit of 1 MW.

The cost of the battery credit is based on the least expensive generation alternative, which is a combustion turbine. A base cost of $526/KW (in 1991 dollars) is used for this credit. The annual cost savings from avoiding the investment in this generation is credited to the battery.

The transmission credit is basically computed on the basis of the cost of deferring the project. The actual capital cost expenditure is considered to be postponed by a number of years. The annual cost savings due to the postponement is credited to the battery benefits. The distribution benefits are also calculated similarly.

The fourth and last benefit computed in this study is the value of service or cost of outages. The actual cost or value of service used in this study is discussed in Section 7.2. For each of the five candidates of battery application analyzed in this study, it is assumed that the total amount of energy not served or KWH interrupted per year is equal to the total battery KWH rating. This means that, on the average, the sum of energy supplied to the customers by the battery during the interruptions over a period of one year is equal to its total energy rating. The implication of this assumption will be discussed later.

The economic parameters used in computing the annual cost and net present value (NPV) are shown in Table 8.1.

TABLE 8.1

GENERAL ECONOMIC PARAMETERS

Interest Rate	=	7.71%
O&M	=	2.50%
Insurance	=	0.11%
Ad Val Tax	=	0.74%
Plant Life (Years)	=	30
Escalation Rate	=	4.50%
Discount Rate	=	7.70%

The battery storage system costs assumed for base cases are shown in Table 8.2

TABLE 8.2

BATTERY STORAGE COSTS FOR BASE CASES

Estimated Battery Capital Cost	$140 /kWh(1993)
Battery Salvage Value	20%
Battery Shelf Life(Years)	15
Battery O&M	0.25%
Estimated Battery Replacement Cost	$112 /kWh(1993)
Estimated PC+BOP Capital Cost	$200 /kW(1993)
Escalation Rate	4.50%

For the battery alone a different life is used than for the entire battery storage plant. The O&M used is 0.25% of the capital cost. Amortising the capital cost is levelized over the plant life. All other costs are escalated at the rate shown in Table 8.1. The salvage value ofthe battery cells is included in computing the levelized annual cost. The cost of replacing the battery is calculated first, and its percent of cost reduction due to salvage is determined. The present worth of the cost reduction is computed and subtracted from the capital cost of the battery. The resulting cost is amortized over the life of the battery to compute the annual cost of the battery. The replacement cost of battery cells is included as needed. The converter and balance of plant are assumed to have a 30 year life and no salvage value.

8.2 Summary of Five Application Cases

Benefit to cost ratio for battery application at five different locations for T&D deferment have been computed. The results are summarized in Table 8.3.

The benefit to cost ratio of Habersham EMC Meter Point #8 (Hollywood substation) is greater than 1. The next best benefit to cost is at Planters #9 (Egypt substation). The remaining three are ranked as Satilla #12 Lanes Bridge substation, Vidalia and Warrentown. The detailed results for each case are presented in the next few sections.

TABLE 8.3

SUMMARY OF NET PRESENT VALUE

BENEFIT ITEMS	HOLLYWOOD	EGYPT	SATILLA	VIDALIA	WARRENTON
	LOCATION				
GENERATION	$667,972	$1,959,385	$801,566	$19,326,656	$19,415,719
TRANSMISSION		3,677,200		1,432,366	1,263,723
DISTRIBUTION	206,603	0	206,603	206,603	0
BACK-UP SOURCE CREDIT	2,058,127	1,953,778	417,220	9,635,678	10,106,005
TOTAL SAVINGS	2,932,702	7,590,363	1,425,389	30,601,303	30,785,447
BATTERY COST	1,966,781	6,022,418	2,291,083	54,051,315	57,167,755
BENEFIT/COST	1.49	1.26	0.62	0.57	0.54
BATTERY SIZE					
KWH	7,500	22,000	9,000	217,000	218,000
HOURS	5	4	6	7	5

8.2.1 Habersham #8 Hollywood

The detailed economic analysis for a battery application at this location is shown in Table 8.4. The benefit to cost ratio, as shown at the bottom of the table, is 1.49 and is the highest of the five applications investigated. The generation capacity (reserve) benefit is calculated for 750 KW (7500 ÷ 10 hours). There is no transmission deferral here. The distribution deferment avoids adding a second transformer. By placing batteries further down in the distribution system, additional benefits (deferment, loss reduction, shunt capacitor credit, etc.) may be possible. However, these are expected to be a smaller percentage of the total benefits and are more difficult to determine with reasonable accuracy. Hence, these are ignored.

In terms of benefits, the value of service [costed at $15.45 per KWH (1993)] accounts for 70% of the total benefit, followed by generation capacity credit and distribution deferment. The back-up source or value of source benefit alone is sufficient to pay for the estimated battery costs.

TABLE 8.4

ESTIMATED VALUE OF BENEFITS AND BATTERY COSTS
FOR
HABERSHAM #8 HOLLYWOOD

ASSUMED BATTERY SIZE= 7,500 KWH ; 5 HRS

YEAR	ANNUAL SAVINGS GENERATION	TRANSMISSION	DISTRIBUTION	BACK-UP/ RELIABILTY CREDIT	TOTAL SAVINGS	NET VALUE $/KWH	ANNUAL BATTERY COST
1997	61,602	0	35,973	138,183	235,758	31	174,048
1998	62,376	0	36,425	144,401	243,203	32	174,845
1999	63,186	0	36,897	150,899	250,982	33	175,677
2000	64,031	0	37,391	157,690	259,113	35	176,548
2001	64,915	0	37,907	164,786	267,608	36	177,457
2002	65,839	0	38,447	172,201	276,487	37	178,407
2003	66,804	0	39,010	179,950	285,765	38	179,400
2004	67,812	0	39,599	188,048	295,460	39	180,438
2005	68,866	0	40,215	196,510	305,591	41	181,523
2006	69,968	0	40,858	205,353	316,179	42	182,656
2007	71,119			214,594	285,713	38	183,840
2008	72,321			224,251	296,572	40	185,078
2009	73,578			234,342	307,920	41	186,371
2010	74,892			244,888	319,779	43	187,722
2011	76,264			255,907	332,172	44	189,135
2012	77,698			267,423	345,122	46	302,665
2013	79,197			279,457	358,655	48	303,968
2014	80,764			292,033	372,796	50	305,328
2015	82,400			305,174	387,575	52	306,751
2016	84,111			318,907	403,018	54	308,237
2017	85,898			333,258	419,156	56	309,790
2018	87,766			348,255	436,021	58	311,413
2019	89,718			363,926	453,644	60	313,109
2020	91,757			380,303	472,060	63	314,881
2021	93,889			397,416	491,305	66	316,733
2022	96,116			415,300	511,416	68	318,668
2023	98,444			433,989	532,432	71	320,691
2024	100,876			453,518	554,394	74	322,804
2025	103,418			473,927	577,344	77	325,013
2026	106,074			495,253	601,327	80	327,321
NET P.V. (1993 $)	667,972	0	206,603	2,058,127	2,932,703	391	1,966,781

Value of Unserved Energy	=	$15.45	/kwh (1993)
Estimated Battery Capital Cost	=	$140	/kWh(1993)
Battery Salvage Value	=	20%	
Battery Shelf Life(Years)	=	15	
Battery O&M	=	0.25%	
Estimated Battery Replacement Cost	=	$112	/kWh(1993)
Estimated PC+BOP Capital Cost	=	$200	/kW(1993)
(a) Generation Capital Deffered	=	$513,742	($1,997)
(b) Transmission Capital Deffered		$0	($1,997)
(c) Distribution Capital Deffered	=	$300,000	($1,997)
Estimated Battery Capital Cost	=	$1,252,145	($1,997)
Estimated PCS+BOP Capital Cost	=	$357,756	($1,997)
Estimated Battery Replacement Cost	=	$1,938,603	($2,012)
Estimated Battery 2nd Replacement Cost	=		
Equivalent 30 Year Life Cost	=	$202	/kWh(1993)
		$1,008	/kW(1993)
BENEFIT/COST RATIO		1.49	

Because the base case showed positive benefits, several sensitivity cases were run. The results of these sensitivity cases are summarized in Table 8.5.

TABLE 8.5

RESULTS OF SENSITIVITY ANALYSIS
FOR
HABERSHAM #8 HOLLYWOOD

BATTERY SIZE 7500 KWH ; 5 HOURS

	BASE CASE	CASE-1	CASE-2	CASE-3	CASE-4	CASE-5	CASE-6	CASE-7
BATTERY COST($/KWH)	$140	$223						$223
PCS+BOP COST($/KW)	$200		$400					$400
BATTERY SHELF LIFE(YRS)	15			10				10
SALVAGE VALUE	20%				40%			40%
VALUE OF UNSERVED ENERGY($/KWH)	$15.45					$8.25		$8.25
DISTRIBUTION BENEFITS(YRS)	10						30	30
BENEFIT/COST RATIO	1.49	1	1.27	1.42	1.68	1	1.58	0.76

NOTE: ONLY CHANGED VALUES ARE SHOWN; OTHER VALUS SAME AS BASE CASE.

Detailed estimated benefits are contained in Appendix F. In the first case, (Case-1), it is shown that the battery's cost can be as high as $223/KWH (1993), which is about 60% higher than the base case, for the value of benefits to equal the cost of battery storage. In the second case, the converter and balance of plant (PCS + BOP) cost was doubled to $400/KWH (1993) and this reduced the benefit to cost ratio from 1.49 to 1.27. These two sensitivity cases show that the battery cells cost has a higher effect on the overall cost as compared to the converter and other costs.

In the third case, the battery life was reduced to 10 years from 15 years. This means two battery replacements are included in this case-3 as compared to only one battery replacement in the base case. The benefit to cost ratio decreased from 1.49 to 1.42 which is not a substantial reduction. Thus, there may be economic advantages in improving the cycle life of lead acid batteries, but the shelf life is not significant as compared to the battery cost itself.

In the fourth case, the salvage value was doubled from 20%. Surprisingly, the benefit to cost ratio increased to 1.68. This may be partly explained by the escalation used in computing replacement battery cost. Essentially, the salvage part of the battery cost is escalated by 4.5% because at the end of battery life, the trade-in value of the battery is assumed to be equal to the salvage percentage of the new battery cost.

The fifth sensitivity case involved the value of service or backup source credit. As noted earlier, this item contributed most to the battery benefits. Hence, the question is how low can this value of service be for the breakeven cost. As shown in Table 8.5, for this cost $8.25/KWH (1993) the benefits and cost of battery are breakeven. The $8.25 per KWH is fairly close to $5.68/KWH in Table 7.1.

In the sixth sensitivity case, the distribution benefits were extended to 30 years. The base case showed the distribution transformer deferment for 10 years only. Because the battery can be moved to another location, similar distribution benefits may continue to accrue. This case shows an increased benefit to cost ratio of 1.58. The cost of moving the battery and any change in value of service are not recognized in this case.

The seventh case consists of taking a pessimistic approach and the cost components are a combination of all the sensitivity values used in the earlier 6 cases. Only salvage value and distribution benefits are positive assumptions. As expected, the benefit to cost ratio decreased to 0.76.

Based on the base case and the sensitivity cases, a range of 0.75 (low) - 1.68 (high) for the benefit to cost ratio has been calculated for Habersham #8 Hollywood substation.

8.2.2 Planters #9 Egypt Substation

The estimated value of benefits due to battery storage and the battery costs are presented in Table 8.6. The benefit to cost ratio is 1.26 for base case assumptions. This is the second highest benefit to cost ratio of the five applications evaluated in this study. The largest benefit is from transmission deferral. The second largest benefit is from the generation reserve credit and the third benefit is the credit for value of unserved energy or backup source. The distribution related benefits are not included in this table. As mentioned earlier, Egypt substation is served by a radial 46 kV line and it traverses swampy right-of-way. Hence, any outage and repair may take longer than the typical outage to restore power. The outage history shows the average outage duration to be almost 2 hours (Table 7.2). The frequency of outages has been 1.2 occurrences per year. The value of service for residential customers ranges from $0.02 to $5.00 for one hour interruption (Table 7.1). Based on longer outage duration and higher frequency of outages the highest residential cost of outage of $5.00/KWH was used in this case.

The transmission deferral was assumed to be good for 10 years. Beyond ten years, the load in the area may be sufficiently higher to require a new or second transmission line. The time horizon for transmission plans is about 10 years, beyond which the picture becomes unclear.

Two sensitivity cases were run for the Egypt substation. The first case was to determine the value of service (or cost of outage) which makes the sum of the benefits to be breakeven with cost.

TABLE 8.6

ESTIMATED VALUE OF BENEFITS AND BATTERY STORAGE COSTS
FOR
PLANTERS #9 EGYPT

ASSUMED BATTERY SIZE= 22,000 KWH ; 4 HOURS

YEAR	ANNUAL SAVINGS GENERATION	TRANSMISSION	DISTRIBUTION	BACK-UP/ RELIABILTY CREDIT	TOTAL SAVINGS	NET VALUE $/KWH	ANNUAL BATTERY COST
1997	180,699	640,252	0	131,177	952,128	43	536,095
1998	182,971	648,301	0	137,080	968,352	44	538,563
1999	185,345	656,713	0	143,249	985,306	45	541,141
2000	187,826	665,503	0	149,695	1,003,023	46	543,836
2001	190,418	674,689	0	156,431	1,021,538	46	546,651
2002	193,127	684,288		163,470	1,040,885	47	549,594
2003	195,958	694,318		170,827	1,061,103	48	552,669
2004	198,917	704,801		178,514	1,082,231	49	555,882
2005	202,008	715,755		186,547	1,104,310	50	559,240
2006	205,239	727,202		194,942	1,127,382	51	562,749
2007	208,615			203,714	412,329	19	566,416
2008	212,143			212,881	425,024	19	570,247
2009	215,830			222,461	438,290	20	574,252
2010	219,682			232,471	452,154	21	578,436
2011	223,708			242,933	466,641	21	582,809
2012	227,916			253,865	481,780	22	916,073
2013	232,312			265,289	497,601	23	920,144
2014	236,906			277,227	514,133	23	924,399
2015	241,707			289,702	531,409	24	928,845
2016	246,725			302,738	549,463	25	933,491
2017	251,968			316,362	568,329	26	938,346
2018	257,446			330,598	588,044	27	943,420
2019	263,172			345,475	608,646	28	948,722
2020	269,155			361,021	630,176	29	954,263
2021	275,407			377,267	652,674	30	960,053
2022	281,941			394,244	676,185	31	966,104
2023	288,768			411,985	700,753	32	972,427
2024	295,903			430,524	726,428	33	979,034
2025	303,359			449,898	753,257	34	985,939
2026	311,151			470,143	781,294	36	993,154
NET P.V. (1993 $)	1,959,385	3,677,200	0	1,953,778	7,590,363	345	6,022,418

Value of Unserved Energy	=	$5.00	/kwh (1993)
Estimated Battery Capital Cost	=	$140	/kWh(1993)
Battery Salvage Value	=	20%	
Battery Shelf Life(Years)	=	15	
Battery O&M	=	0.25%	
Estimated Battery Replacement Cost	=	$112	/kWh(1993)
Estimated PC+BOP Capital Cost	=	$200	/kW(1993)
(a) Generation Capital Deffered	=	$1,506,975	($1,997)
(b) Transmission Capital Deffered		$5,339,510	($1,997)
(c) Distribution Capital Deffered	=	$0	($1,997)
Estimated Battery Capital Cost	=	$3,672,957	($1,997)
Estimated PCS+BOP Capital Cost	=	$1,311,770	($1,997)
Estimated Battery Replacement Cost	=	$5,686,568	($2,012)
Estimated Battery 2nd Replacement Cost	=		
Equivalent 30 Year Life Cost	=	$211	/kWh(1993)
		$842	/kW(1993)
BENEFIT/COST RATIO		1.26	

At value of service $ 1.00/KWH and all the other values being the same, this ratio was 1.0. The detailed results from this analysis are included in Appendix F (Table F8). The second sensitivity case involved extending the transmission benefit to 30 years upon the premise that battery can be moved to another location when transmission can not be deferred anymore. The benefit to cost ratio in this case turned out to be 1.8, assuming the same amount of deferred credit is available. Because the ratio is greater than unity, even if the T&D benefit in the later years is less than in the earlier years, the benefit may be higher than the cost incurred. Thus, the battery storage at Egypt substation shows beneficial application potential and may be considered as a serious candidate for demonstration.

8.2.3 Sattila #12 Lanes Bridge

The battery storage as studied for this location is sized to defer the distribution transformer by 10 years. The calculated benefit to cost ratio is 0.62 (Table 8.7) which is much smaller than the two previously discussed locations. The largest benefit is from generation capacity reserve (900 KW) credit. The backup source credit is next highest with the distribution transformer deferment credit being the least.

Because Satilla #12 Lanes Bridge is a small substation serving mostly residential customers, average value of service of $2.50/KWH (in 1993 dollars) from Table 7.1, was assumed. A sensitivity case (Table F10, Appendix F) indicated that at $8.00/KWH (in 1993 dollars) for value of service, the benefit to cost ratio is unity. As shown in Table 7.2, average outage duration in the last 5 years is about 6 hours. Hence, a higher value of service credit than indicated in Table 7.1 may be applicable. If such high backup source credit can be justified, then Lanes Bridge could be a candidate for battery energy storage application.

8.2.4 Vidalia

The main reason for considering battery storage at this location is to defer installation of an additional 140 MVA, 230/115 kV transformer. As discussed in Section 7.0, because of parallel 115 kV lines, a rather large battery storage is needed to reduce overload on the existing transformers. The benefit to cost ratio is 0.57 (Table 8.8) with generation reserve capacity benefit (for 21.7 MW) being the largest. Back-up source credit is the next largest benefit.

TABLE 8.7

ESTIMATED VALUE OF BENEFITS AND BATTERY STORAGE COSTS
FOR
SATILLA #12 LANES BRIDGE

ASSUMED BATTERY SIZE = 9,000 KWH ; 6 HOURS

YEAR	ANNUAL SAVINGS GENERATION	TRANSMISSION	DISTRIBUTION	BACK-UP/ RELIABILTY CREDIT	TOTAL SAVINGS	NET VALUE $/KWH	ANNUAL BATTERY COST
1997	73,922	0	35,973	28,012	137,907	15	201,887
1998	74,852	0	36,425	29,273	140,549	16	202,808
1999	75,823	0	36,897	30,590	143,310	16	203,771
2000	76,838	0	37,391	31,967	146,196	16	204,776
2001	77,898	0	37,907	33,405	149,211	17	205,827
2002	79,007	0	38,447	34,908	152,362	17	206,925
2003	80,165	0	39,010	36,479	155,654	17	208,073
2004	81,375	0	39,599	38,121	159,095	18	209,272
2005	82,640	0	40,215	39,836	162,691	18	210,525
2006	83,961	0	40,858	41,629	166,448	18	211,835
2007	85,342	0		43,502	128,845	14	213,203
2008	86,786	0		45,460	132,246	15	214,633
2009	88,294	0		47,505	135,799	15	216,128
2010	89,870	0		49,643	139,513	16	217,689
2011	91,517	0		51,877	143,394	16	219,321
2012	93,238	0		54,212	147,450	16	355,492
2013	95,037	0		56,651	151,688	17	356,987
2014	96,916	0		59,200	156,117	17	358,548
2015	98,880	0		61,864	160,745	18	360,180
2016	100,933	0		64,648	165,581	18	361,885
2017	103,078	0		67,558	170,635	19	363,667
2018	105,319	0		70,598	175,917	20	365,529
2019	107,661	0		73,775	181,436	20	367,475
2020	110,109	0		77,094	187,203	21	369,509
2021	112,667	0		80,564	193,230	21	371,633
2022	115,339	0		84,189	199,528	22	373,854
2023	118,133	0		87,978	206,110	23	376,175
2024	121,051	0		91,937	212,988	24	378,600
2025	124,101	0		96,074	220,175	24	381,134
2026	127,289	0		100,397	227,686	25	383,782
NET P.V. (1993 $)	801,566	0	206,603	417,220	1,425,390	158	2,291,083

Value of Unserved Energy	=	$2.61	/kwh (1993)
Estimated Battery Capital Cost	=	$140	/kWh(1993)
Battery Salvage Value	=	20%	
Battery Shelf Life(Years)	=	15	
Battery O&M	=	0.25%	
Estimated Battery Replacement Cost	=	$112	/kWh(1993)
Estimated PC+BOP Capital Cost	=	$200	/kW(1993)
(a) Generation Capital Deffered	=	$616,490	($1,997)
(b) Transmission Capital Deffered	=	$0	($1,997)
(c) Distribution Capital Deffered	=	$300,000	($1,997)
Estimated Battery Capital Cost		$1,502,573	($1,997)
Estimated PCS+BOP Capital Cost	=	$357,756	($1,997)
Estimated Battery Replacement Cost	=	$2,326,323	($2,012)
Estimated Battery 2nd Replacement Cost	=		
Equivalent 30 Year Life Cost	=	$196	/kWh(1993)
		$1,175	/kW(1993)
BENEFIT/COST RATIO	=	0.62	

TABLE 8.8

ESTIMATED VALUE OF BENEFITS AND BATTERY STORAGE COSTS
FOR VIDALIA

ASSUMED BATTERY SIZE= 217,000 KWH ; 7 HOURS

YEAR	ANNUAL SAVINGS GENERATION	TRANSMISSION	DISTRIBUTION	BACK-UP/ RELIABILTY CREDIT	TOTAL SAVINGS	NET VALUE $/KWH	ANNUAL BATTERY COST
1997	1,782,349	434,068	35,973	646,941	2,899,332	13	4,747,698
1998	1,804,757	439,526	36,425	676,054	2,956,761	14	4,769,291
1999	1,828,173	445,228	36,897	706,476	3,016,775	14	4,791,856
2000	1,852,643	451,188	37,391	738,268	3,079,490	14	4,815,436
2001	1,878,215	457,415	37,907	771,490	3,145,027	14	4,840,077
2002	1,904,936		38,447	806,207	2,749,590	13	4,865,827
2003	1,932,861		39,010	842,486	2,814,357	13	4,892,736
2004	1,962,041		39,599	880,398	2,882,038	13	4,920,856
2005	1,992,535		40,215	920,016	2,952,766	14	4,950,241
2006	2,024,402		40,858	961,416	3,026,676	14	4,980,949
2007	2,057,702			1,004,680	3,062,382	14	5,013,038
2008	2,092,501			1,049,891	3,142,391	14	5,046,571
2009	2,128,865			1,097,136	3,226,001	15	5,081,614
2010	2,166,866			1,146,507	3,313,373	15	5,118,233
2011	2,206,578			1,198,100	3,404,677	16	5,156,500
2012	2,248,076			1,252,014	3,500,090	16	8,438,607
2013	2,291,441			1,308,355	3,599,796	17	8,473,454
2014	2,336,758			1,367,231	3,703,989	17	8,509,870
2015	2,384,115			1,428,756	3,812,871	18	8,547,924
2016	2,433,602			1,493,050	3,926,652	18	8,587,691
2017	2,485,316			1,560,238	4,045,554	19	8,629,247
2018	2,539,357			1,630,448	4,169,806	19	8,672,674
2019	2,595,831			1,703,818	4,299,649	20	8,718,054
2020	2,654,845			1,780,490	4,435,335	20	8,765,477
2021	2,716,515			1,860,612	4,577,128	21	8,815,033
2022	2,780,961			1,944,340	4,725,301	22	8,866,820
2023	2,848,306			2,031,835	4,880,141	22	8,920,937
2024	2,918,682			2,123,268	5,041,950	23	8,977,490
2025	2,992,225			2,218,815	5,211,040	24	9,036,587
2026	3,069,077			2,318,661	5,387,739	25	9,098,343
NET P.V. (1993 $)	19,326,656	1,432,366	206,603	9,635,678	30,601,303	141	54,051,315

Value of Unserved Energy	=	$2.50	/kwh (1993)
Estimated Battery Capital Cost	=	$140	/kWh(1993)
Battery Salvage Value	=	20%	
Battery Shelf Life(Years)	=	15	
Battery O&M	=	0.25%	
Estimated Battery Replacement Cost		$112	/kWh(1993)
Estimated PC+BOP Capital Cost		$200	/kW(1993)
(a) Generation Capital Deffered		$14,864,258	($1,997)
(b) Transmission Capital Deffered		$3,620,000	($1,997)
(c) Distribution Capital Deffered		$300,000	($1,997)
Estimated Battery Capital Cost		$36,228,715	($1,997)
Estimated PCS+BOP Capital Cost	=	$7,393,615	($1,997)
Estimated Battery Replacement Cost	=	$56,090,237	($2,012)
Estimated Battery 2nd Replacement Cost	=		
Equivalent 30 Year Life Cost	=	$192	/kWh(1993)
		$1,341	/kW(1993)
BENEFIT/COST RATIO		0.57	

An average value of \$2.50/KWH was used, because multiple 230 kV and 115 kV lines are connected to this substation. Hence, longer interruptions are expected to be rare and also infrequent.

Maximum deferral of an additional transformer is only 5 years with this battery size. Hence, the deferment benefit is not very high. The battery may be placed at a lower voltage (46 kV or below) location thus postponing some distribution transformer addition or replacement. Here it was assumed that at least one such deferment is possible for a period of 10 years. This was the smallest calculated benefit. By placing smaller sized batteries considerably more distribution benefit may be possible.

Again two sensitivity cases were run. The first case assumed a higher value of service of \$8.60/KWH (1993 dollars) to give a breakeven benefit to cost ratio (Table F11, Appendix F). Any higher backup source credit needs to be justified from three principal factors (alone or in combination). They are type of customer load, duration of interruption and frequency of interruption. In the economic evaluation, the number of outages multiplied by their duration per year (i.e., when battery storage is called upon in one year on the average as a backup source) is assumed to be equal to the battery energy rating. The second case extended the T&D benefits to 30 years, and the benefit to cost ratio increased to 0.63 only (Table F12, Appendix F).

8.2.5 Warrenton

This is a second transmission/transformer deferment candidate considered in this study. The battery energy (KWH) storage is almost the same as Vidalia, but would require a faster discharge rate. Hence, the converter costs are higher in this case as compared to Vidalia. The benefit to cost ratio was calculated to be 0.54 (Table 8.9) which is the lowest of the five cases. The generation benefits were the highest, followed by back-up source credit and transmission credit. As in the case of Vidalia, there are multiple 230 kV and 115 kV transmission lines serving Warrenton station. Because 230 kV and 115 kV lines are paralleled, a rather large capacity battery is needed. The transformer addition could be postponed at most only 10 years.

TABLE 8.9

ESTIMATED VALUE OF BENEFITS AND BATTERY COSTS
FOR WARRENTON

ASSUMED BATTERY SIZE= 218,000 KWH ; 5 HOURS

YEAR	ANNUAL SAVINGS GENERATION	TRANSMISSION	DISTRIBUTION	BACK-UP/ RELIABILTY CREDIT	TOTAL SAVINGS	NET VALUE $/KWH	ANNUAL BATTERY COST
1997	1,790,563	220,032	0	678,519	2,689,114	12	5,058,984
1998	1,813,074	222,798	0	709,053	2,744,925	13	5,082,148
1999	1,836,598	225,689	0	740,960	2,803,247	13	5,106,353
2000	1,861,181	228,710	0	774,303	2,864,194	13	5,131,648
2001	1,886,870	231,867	0	809,147	2,927,883	13	5,158,081
2002	1,913,715	235,165	0	845,558	2,994,439	14	5,185,704
2003	1,941,768	238,613	0	883,609	3,063,989	14	5,214,569
2004	1,971,083	242,215	0	923,371	3,136,669	14	5,244,734
2005	2,001,718	245,980	0	964,923	3,212,620	15	5,276,256
2006	2,033,731	249,913	0	1,008,344	3,291,988	15	5,309,196
2007	2,067,184			1,053,720	3,120,904	14	5,343,619
2008	2,102,144			1,101,137	3,203,281	15	5,379,591
2009	2,138,676			1,150,688	3,289,364	15	5,417,182
2010	2,176,852			1,202,469	3,379,321	16	5,456,464
2011	2,216,746			1,256,580	3,473,326	16	5,497,513
2012	2,258,436			1,313,126	3,571,562	16	8,797,469
2013	2,302,001			1,372,217	3,674,218	17	8,835,323
2014	2,347,527			1,433,967	3,781,494	17	8,874,881
2015	2,395,101			1,498,495	3,893,597	18	8,916,219
2016	2,444,817			1,565,928	4,010,744	18	8,959,417
2017	2,496,769			1,636,394	4,133,164	19	9,004,559
2018	2,551,060			1,710,032	4,261,092	20	9,051,732
2019	2,607,793			1,786,984	4,394,777	20	9,101,028
2020	2,667,080			1,867,398	4,534,477	21	9,152,542
2021	2,729,034			1,951,431	4,680,465	21	9,206,375
2022	2,793,776			2,039,245	4,833,021	22	9,262,630
2023	2,861,432			2,131,011	4,992,443	23	9,321,416
2024	2,932,132			2,226,907	5,159,039	24	9,382,848
2025	3,006,014			2,327,117	5,333,131	24	9,447,045
2026	3,083,220			2,431,838	5,515,058	25	9,514,130
NET P.V. (1993 $)	19,415,719	1,263,723		10,106,005	30,785,448	141	57,167,755

Value of Unserved Energy	=	$2.61	/kwh (1993)
Estimated Battery Capital Cost	=	$140	/kWh(1993)
Battery Salvage Value	=	20%	
Battery Shelf Life(Years)	=	15	
Battery O&M	=	0.25%	
Estimated Battery Replacement Cost		$112	/kWh(1993)
Estimated PC+BOP Capital Cost		$200	/kW(1993)
(a) Generation Capital Deffered		$14,932,756	($1,997)
(b) Transmission Capital Deffered		$1,835,000	($1,997)
(c) Distribution Capital Deffered		$0	($1,997)
Estimated Battery Capital Cost		$36,395,668	($1,997)
Estimated PCS+BOP Capital Cost	=	$10,398,762	($1,997)
Estimated Battery Replacement Cost	=	$56,348,717	($2,012)
Estimated Battery 2nd Replacement Cost	=		
Equivalent 30 Year Life Cost	=	$202	/kWh(1993)
		$1,008	/kW(1993)
BENEFIT/COST RATIO		0.54	

There is no obvious distribution deferment. However, several smaller size batteries could be located in order to obtain deferment of distribution facilities and equipment.

Again two sensitivity cases were run. Increasing backup source credit to $9.40/KWH (in 1993 dollars) made the benefit to cost ratio to be unity (Table F13, Appendix F). Extending the transmission benefits to 30 years, increased the benefit to cost ratio to 0.56 (from 0.54).

APPENDIX A

BENEFITS OF BATTERY STORAGE

APPENDIX A

BENEFITS OF BATTERY STORAGE

Battery potential benefits that battery attributes and control capability can provide are described in this appendix. There are two considerations to be kept in mind in evaluating the potential benefits of batteries:

> Battery storage systems are different from other power generation and transmission facilities. They are even quite different from the forms of energy storage that are presently in use (compressed air and pumped hydro). The unique terms and attributes of battery storage systems are described in Appendix B. Brief descriptions of battery energy storage system controls and hardware are given in Appendix C. The unique attributes and control capability need to be considered when evaluating them as an alternative to other power generation and T&D equipment.
>
> Battery storage systems may not be able to provide all of the benefits listed below at the same time. Some of them are what has been termed "mutually exclusive." That is, if credit is taken for one benefit, some others may not qualify for credit. For instance, if a battery is used to defer a T&D equipment, some of the reduction in losses it can provide will be lost because the average loading of the existing lines will increase. However, some apparently mutually exclusive benefits may be less mutually exclusive than they at first appear. For instance, if two potential benefits do not each require the battery at the same time, or during the same season, then perhaps the battery can provide both. Further, there may be times when a battery can provide only one of two benefits, but at times one is more valuable, and at other times the other is more valuable. When this is the case, a battery may not fully provide either benefit, but will be of more value that either alone would indicate. In this situation, operators would decide on a day to day or hour to hour basis just how the battery should best be used. This kind of shared battery use is difficult to evaluate without a detailed year-long chronological simulation, but may

be important to a fair evaluation. Other examples of mutual exclusivity are listed in Appendix D.

The potential benefits include:

Generation -- batteries can provide spinning reserve, load following, area regulation, and load leveling or peak shaving to:

Defer generating capacity — By storing energy at night and releasing it during peak load times, batteries can reduce generation requirements. The spinning reserve and area and frequency regulation applications described below also contribute to a reduced generation requirement.

Reduce production cost — Batteries can be charged at night when energy costs are low, and discharged during the day when costs are high. Batteries may also be charged from off-system purchases during off-peak hours.

Provide spinning reserve — Each utility in a pool has an obligation to have a certain amount of generation on-line over and above the forecasted load so that sufficient generation is available to meet load when a generating unit trips. Because there is more generation on-line than load, some units are operated at less than their full capacity. Ramping rate also enters into the picture. Batteries can sit efficiently at zero output and be activated quickly and automatically when needed, so it can provide spinning reserve at far less operating cost than a spinning generator. Generating units capable of providing spinning reserve can also be operated at their most efficient power level rather than at a lower power level when a battery provides spinning reserve.

Provide area and frequency regulation — Each utility in a pool has an obligation to follow its own load to prevent tie line loading from deviating significantly from scheduled interchanges. Doing so also keeps frequency constant. When deviations from schedule do occur, each utility must correct and "net out" those deviations within 10 minutes. This usually means having highly responsive generating units well operating below maximum capability, or far from their most efficient operating points, equal to as much as 3% of the system load operating in a regulating mode. Using batteries to follow load allows generation to be operated in its most efficient manner. The generation would need to be maneuvered only enough to keep the battery charged to 70 to 80% of its capacity so it can handle both increases and decreases in load.

Reduce operating constraints and minimum load problems, and reduce plant O&M costs

Utilities often have limitations such as generators that can't be cycled, generators that are costly to cycle, generators whose loading can't be changed quickly and rapid load changes. Solutions include leaving units on-line around the clock and starting combustion turbines or starting cycled units ahead of the load. Batteries can follow load and level the load to reduce cycling.

Transmission & Distribution -- batteries can serve load peaks and respond quickly to:

Defer lines and transformers

Transmission and distribution systems are planned to carry the system peak load with one or more lines or transformers out of service. The T&D investment is reduced when batteries are used to store energy during off-peak hours and serve the load during the daytime peak. Overall this could save $100 to $200 per kW of load, but the savings can be much greater if batteries are placed judiciously where T&D costs are high. Some utilities have locations where T&D costs are several times the system-wide $100 to $200 per kW number. Batteries do not need to be cycled to qualify for this benefit, but they do need to be at least charged and ready to cover a T&D equipment outage should it occur during peak load.

Reduce line losses

Because line losses are about four times higher during peak load hours than they are during off peak hours, charging batteries at night and discharging them during the day will reduce T&D losses from their usual 5 to 8% by 0.5% to 1.0% when the battery is operating. A battery which is cycled daily or almost daily provides significant loss reduction benefit.

Regulate voltage

Batteries can improve voltage regulation in two ways. One is by supplying active power to customers and thereby reducing the loading on the network. The second is by supplying reactive power to the network. Battery power converters can readily be designed to supply active and reactive power. If the converter is designed to a power factor rating like a generator, it will be capable of supplying both active and reactive power at the same time. The converter is capable of responding to voltage excursions much more quickly than a generator, thus provides excellent voltage control.

Increase transfers

Batteries can respond quickly to controls or operators to improve voltage stability, first-swing stability, and steady state oscillatory stability, and thereby increase transfers in stability limited systems. Batteries can improve voltage stability by supplying both active and reactive power when a system is hit by a contingency which threatens voltage stability. Batteries can improve first-swing stability by quickly injecting power into a decelerating system or absorbing power from an accelerating system immediately following fault clearing. Battery power can also be modulated by a power system stabilizer to provide system damping.

Environmental benefits include:

Reduced air emissions

Batteries can reduce air emissions by storing energy from low emission plants at night, and supplying load during the day so high emission plants can be operated at lower output or left off-line. Because batteries have virtually no emissions themselves, they are ideal for this purpose. Battery turn-around losses (about 20%) need to be recognized as there will be emissions associated with them.

Improved urban air quality

Urban air quality can be improved by importing power from remote plants at night and storing it in batteries for use the next day.

Reduced electromagnetic fields	Batteries located near customers, and cycled to level the load, will reduce the high daytime current in transmission lines. This, in turn, will reduce the magnetic fields. Charging the batteries at night will increase the current in lines at night. However, the reduction in the high current during the day may be more beneficial than the increase in low night currents is harmful.
Reduce land requirements for T&D and generation	Use of land for electric utility equipment is a sensitive subject today. To the extent batteries can defer generation and T&D equipment without using a lot of land themselves, batteries may help where land simply isn't available for lines and generating plants.

Strategic -- batteries can reduce the risk of high, unnecessary system investments through:

Acting as an any-Fuel source	Batteries may be able to store energy from various sources to help cover contingencies such as a nuclear moratorium or other major upset in fuel supply.
Hedge to avoid unneeded investment	Batteries can be a hedge to avoid unneeded investment in T&D facilities or generating plants. Because a battery can be installed quickly, and can later be moved, it allows a wait-and-see attitude toward high load growth.
Means to serve difficult to reach load	Because of low environmental impact, batteries can be installed anywhere there is space for them. They thus may provide service to growing load that cannot be quickly reached by overhead lines or cables.

Other -- batteries can provide other miscellaneous benefits such as:

Power quality	Batteries are, in effect, a 'local' power source independent of the T&D system. They can thus ride through temporary T&D system outages like an uninterruptable power supply (UPS). The converter on a battery can also regulate voltage, thereby improving power quality further.

Reliability (Backup source)	Batteries can supply load for up to several hours, and thus can not only act as a UPS, but can also carry critical loads through outages lasting several hours.
Black start	Batteries can operate independently of the grid, and thus can startup and carry critical loads following outages. Transformers, subtransmission and distribution lines can be energized. Motors can be started. A battery might be used to help startup a generating plant that normally requires power from the grid for startup.
System modeling	Batteries can be modulated to excite low level system oscillations and provide very useful information on system stability. This can improve analytical studies used to set transfer limits.
Take advantage of energy buy-sell opportunities	Batteries may help utilities that both buy and sell energy. To the extent that such transactions can be scheduled ahead of time, a battery could serve this purpose when it is not needed for on-system services.

Customer-side-of-the-meter applications -- from the customer perspective, batteries might provide:

Demand limiting	Most utilities impose demand charges on larger customers to cover the cost of T&D and generating equipment needed to serve short-duration peaks. These customers could use batteries to control their 30 minute demand and avoid these penalties.
Reliability (Backup source)	Some customers could make use of utility type battery installations in much the same way they use UPS systems or diesel generators for smaller loads.

APPENDIX B

TERMS, ATTRIBUTES, AND OTHER

APPENDIX B

TERMS, ATTRIBUTES, AND OTHER

Attribute

An 'attribute' is a characteristic of batteries that can be used to advantage by an electric utility. Energy storage, fast response, site flexibility, and unattended operation are examples.

Benefit

A battery energy storage 'benefit' is a monetary, strategic, or societal benefit of placing a battery on the utility grid. Benefits include deferred or avoided generation or T&D equipment investments, reduced losses, improved reliability, lower spinning reserve costs, and more efficient operation of generation.

Application

An 'application' is a battery of specific size and in a specific location. It is a 'good' application if the benefits exceed battery cost.

Ratings

Batteries have two key ratings. One is the power rating (kW or MW). It is the maximum power that the battery can provide for an extended period during the discharge part of its cycle. The power rating is dictated by the lowest continuous rating among the components that make up the system: the cells, the busbars, the converter, or the converter transformer. In an optimized design all components will have about the same continuous capability. However, the converter is usually the most limiting device and the one with the least margin. While cell life will be reduced somewhat when a battery is operated above its power rating, GTOs in the converter may fail at a power level as little as 10% above their rating. The converter controls are thus designed to prevent converter overloading.

The maximum continuous charge power level is dictated by the same considerations, and is thus usually the same as the power rating. Note, however, that in practice the charge rate may be lower than the rating to increase battery life if low-cost energy is available over a period sufficient to fully charge the battery at the lower rate.

The second battery rating is its energy storage rating (kWh or MWh). The storage rating is the energy that the battery can provide to the system during a normal continuous discharge. In current designs the energy rating is usually 80% of the energy the battery could provide if discharged fully. The energy rating is solely a function of the individual cell ratings and the number of cell strings in parallel. The battery energy rating can be increased by adding parallel strings of cells.

The batteries produced to date have not been given an overload rating. However, batteries, buswork, transformers, and circuit breakers tolerate some overload. Though a converter cannot be significantly overloaded, a converter could be oversized to take advantage of the overload capability of other components.

KWh Capacity Versus Discharge Rate

The types of cells utilized in utility energy storage are special designs, and do not have a standardized capacity rating based on a certain discharge time such as 20 hours. Such a rating would be of little use in any event in the kinds of applications we are considering. But, more important, is that the amount of energy that can be extracted from a charged battery varies with the discharge time. For instance, in a spinning reserve application we may discharge a battery fully in one hour, while in a T&D deferral or load leveling application we may discharge the same battery over a 4 hour period. In the one-hour discharge we may only get 60 to 80% of the MWh that we could get from a four-hour discharge. The battery discharge characteristics thus need to be considered in specifying the battery, and in costing the battery in cost-benefit studies.

Cell Types

Two types of lead-acid cells are in use. The one first used in utility energy storage applications is the 'flooded' cell. It is typically 14 to 18 inches square and 24 to 30 inches tall. It has a vent on the top covered by a filter so that only hydrogen escapes from the battery. The Southern California Edison installation uses flooded cells, as will the 20 MW battery to be commissioned in Puerto Rico in 1993.

The second type is the 'sealed' or "valve regulated" lead acid battery (sometimes called VRLA for valve regulated lead acid). In this design gelled electrolyte is normally used and contained in a sealed plastic case.

Cycle

The normal 'load-leveling' cycle for a battery is a diurnal one in which the battery is charged at night and discharged to follow load during the day. In most load-leveling applications, batteries will be cycled only on weekdays. In spinning reserve applications there will be no regular charge-discharge cycle. In some special applications multiple shallow charge-discharge cycles may occur over periods of minutes or hours.

Cycle Depth

Batteries can be cycled daily to 'shift' load from peak hours to off-peak hours. However, because battery life is reduced as the depth of discharge is increased, there is an optimum depth of discharge for each application. The optimum depth occurs where the incremental benefit of load-leveling equals the cost of incremental battery loss of life. Though the relationship of the depth of discharge and life loss is not very well known, current practice with flooded cells is to limit the depth of discharge to 80% of the full battery capacity (the battery *rated* capacity may be defined as the capacity that can be used regularly while achieving a stated battery life).

Sealed batteries presently appear to have a shorter life than flooded cells for the same depth of discharge. New designs may close this difference in performance between the two types. Of course, sealed batteries require less maintenance, and this may offset the shorter life. If the reduced life is a constraint for sealed batteries, the sealed types may have an advantage where cycling is infrequent or only partial cycles are needed, and spinning reserve or other uses are the primary function.

In some applications there will be value to the ability to discharge a battery fully. The cell capacity that remains after a normal-depth discharge may be used for spinning reserve or to backup transmission or distribution equipment. Manufacturers indicate that flooded cells can be discharged fully on occasion without significant loss of life. Sealed or valve regulated batteries may eventually have this capability. To achieve full discharge, the power converter must be capable of operating at the end-of-discharge battery voltage.

Life

The life of lead-acid batteries in utility service is not yet well known. Accelerated life tests indicate the life may be as low as five years or as much as 15 to 20 years depending on the application and the type of battery. Life will be at the low end of this range where the battery is cycled frequently and where the depth of discharge is high (Cycle Life, i.e., useful life dependent on number of cycles). It will be near the high end where the battery is essentially in standby service (Shelf Life, i.e., useful life dependent on the age of the battery).

Rapid Cycling

There are two benefits that batteries can provide that will require the battery to be cycled more than once per day. One is frequency regulation and the other is tie line control or area control error (ACE) corrections. Frequency regulation will require many shallow cycles lasting only seconds or minutes. Tie line control cycles will be of modest depth, and will typically last 5 or 10 minutes. These cycles may be in addition to a normal diurnal storage cycle.

Batteries are likely to be useful for frequency regulation only in systems of modest size where variations in customer load are large compared to the total on-line generation. In these systems frequency will vary from second to second and minute to minute unless one or more generators are assigned to tightly control frequency. This kind of duty on generators reduces plant equipment life and increases maintenance. And, even the fastest plants may have difficulty following load, and some utilities do not attempt to regulate frequency tightly because of the cost. Batteries can provide very rapid response to load changes. When called upon to do so frequently (dozens of times each day), the frequent, shallow cycling will reduce battery life somewhat.

Large interconnected systems inherently control frequency well. Even the largest customer load variations are small compared to the mass of many turbine-generator rotors, and thus will not measurably change frequency. However, in these systems each utility has a responsibility of limiting variations in tie flow, or correcting variations quickly when they do occur. Tie flow variations can result from variations in customer load or unscheduled changes in the loading of generating plants. Batteries may provide a significant benefit by taking over the load following task from generators.

Response

A battery system can also be moved almost instantaneously from one operating point to another within its real and reactive operating range shown in Figure B-1. In addition, it can *continuously* move about its operating region in response to a stabilizer or voltage regulator.

Fast response makes the battery a candidate to:

- Respond rapidly to generation shortages or transmission overload (via control signals from control center software or operators),
- Provide LFC or Area Regulation (via control signals from control center software),
- Tightly regulate voltage for the benefit of nearby customers or a larger load area,
- Regulate voltage for improved voltage stability in areas with little generation,
- Provide a damping component of power to raise transfer limits imposed by dynamic stability,

In supplying reactive power to control voltage, the battery system is competing directly with Static Var Systems (SVSs) and generators. The battery system has an advantage over generators in that generators can rarely be sited where voltage control is needed, while batteries are very likely to be sited in areas needing voltage control. A battery system also responds much more quickly to system voltage changes that a generator can.

The reactive capability of a battery system converter is quite similar to that of an SVS. More information on this is in the next section.

APPENDIX C

HARDWARE AND CONTROL

APPENDIX C

HARDWARE AND CONTROL

Major Components

A battery system consists of several components as shown in Figure C-1. The key components are the battery and the power conversion unit (converter).

The battery consists of parallel 'strings' of cells connected in series. Each cell is nominally 1.2 volts, and a string may be from a few hundred volts up to about 2000 volts. The Chino battery, capable of 10 MW, operates at 2000 volts. The string voltage is selected to minimize converter and buswork costs. Converter costs dominate the selection, however, with the optimum design being a function of the available thyristor voltage and current

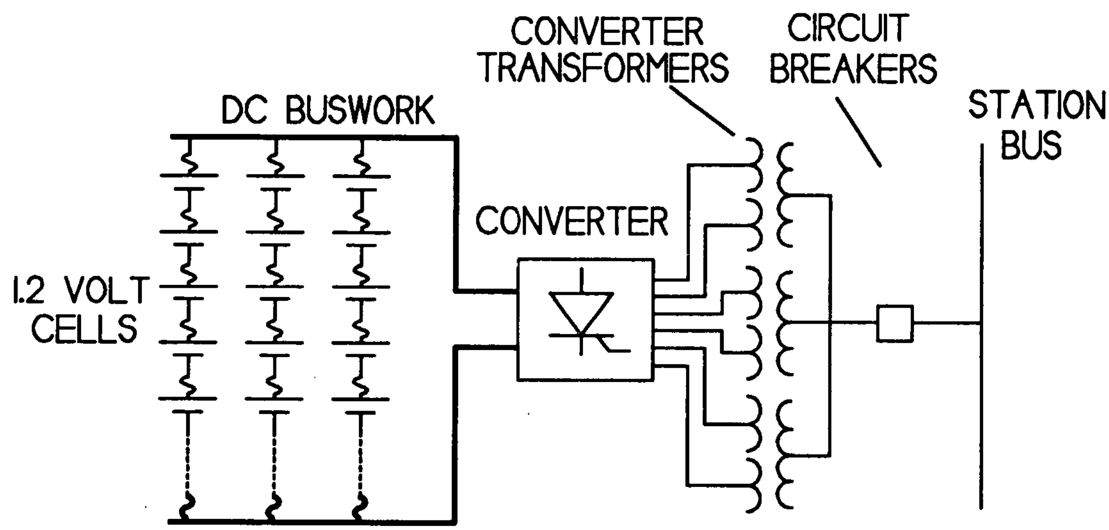


Figure C-1 A battery system consists of several major components.

ratings. Each cell is fused, and each string is fused. The fuse at the cell protects against faults within the string, and the string fuse protects against faults outside the string. The string fuse and the individual battery fuses are coordinated so that the string fuse will open before battery fuses open when a fault external to the string occurs.

The converter consists of a combination rectifier and inverter and a transformer. When the battery is being charged, the converter behaves like a rectifier, changing the ac voltage into dc. When the battery is being discharged, that is, it is supplying power to the system, the converter operates as an inverter.

In the rectifier mode the converter controls the voltage across the battery or the charging current. The voltage and resulting current are adjusted for the desired charge rate. The converter converts the ac voltage to dc by firing the thyristors so that the voltage from each of the transformer windings sums to that needed to cause the desired charge current to flow in the battery.

In the inverter mode the converter essentially chops the dc current into segments, and builds a voltage wave that is an approximation of the normal ac system sine wave. In the case of the Chino battery, a "36 pulse" converter is used.

The converter causes power to flow into the ac bus by shifting its waveform ahead of the waveform of the bus voltage. It charges the battery by making its waveform lag the bus voltage. Reactive power is delivered by making the magnitude of the waveform larger than that of the bus voltage and reactive power is absorbed by making it smaller.

Converters are normally given ratings in MVA, but this rating only applies at rated voltage. Converters are, in reality, current-limited devices. A converter can be used to provide active or reactive current or a combination within its current handling capability. Because real and imaginary current are in quadrature, the square root of the sum of the squares of the reactive and active currents must remain within converter current capability.

A 10 MVA converter can thus supply 7 MW and 7 MVAR, 8 MW and 6 MVAR, etc. at rated voltage. Figure C-2 shows the active and reactive current relationship in a converter. In this example the converter can provide reactive power only when it is operating below its rated active power.

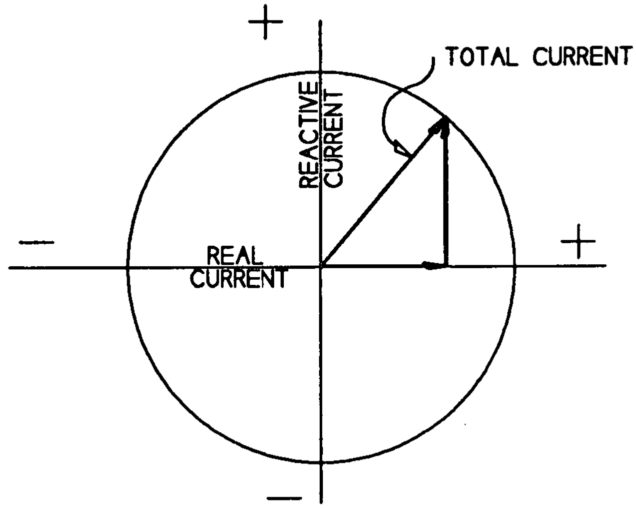


Figure C-2 The total current is the vector sum of the active and reactive current and must be within the converter current rating.

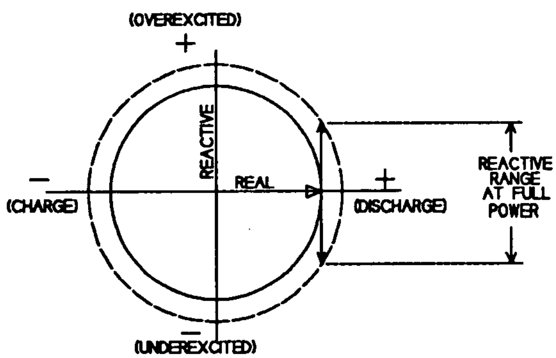


Figure C-3 A modest increase in converter rating will provide a large reactive power capability.

For example, as shown in Figure C-3, increasing the converter MVA (or current) rating by 15% will allow it to provide reactive power up to 57% of the battery MW rating while operating at its MW rating. The battery can supply or absorb reactive power, and can provide a 'dynamic' reactive range of 114% of rated power in this example.

Controls

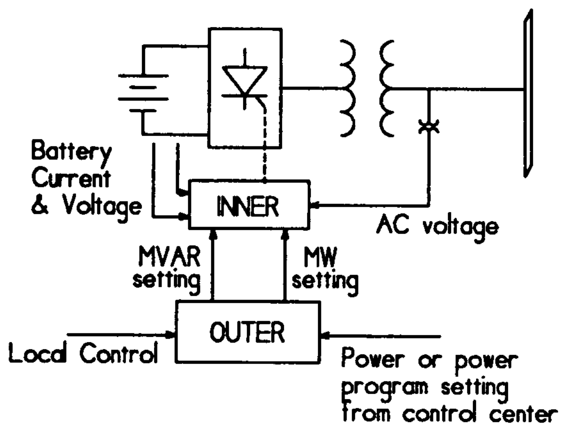


Figure C-4 A battery system has two levels of control, one to drive GTO firing circuits, and one to issue the real power setting.

The battery control system has two levels as shown in Figure C-4. The 'inner loop' provides high speed regulation of the battery power. For instance, if the battery is being controlled to a certain power level, the controller will adjust the GTO firing pulses so that power level is maintained even when the bus voltage is varying. It will also go into a current control mode when a drop in voltage would require converter current to go above the converter rating to hold power.

The inner loop may also include voltage control circuitry. This circuitry adjusts firing pulses to the GTOs so that the converter will produce or absorb reactive current as needed to regulate bus voltage. Again, the controller will go into a current control mode if the GTO current would have to exceed GTO rating in order to hold the desired bus voltage.

The GTO based converter, effectively, synthesizes a waveform that is either larger or smaller in magnitude than the bus voltage, and either leads or lags the bus voltage. The voltage and power level control circuits operate simultaneously to control the magnitude and phase of the waveform respectively. A larger magnitude delivers reactive power to the bus while a lower magnitude absorbs reactive power. A leading voltage delivers active power to the bus (discharge mode) and a lagging voltage absorbs power from the bus (charge mode).

The converter controls must, however, keep total current in the GTOs within their thermal capability. When converter loading is high, one or both of the currents must be limited so that the total current does not exceed the converter rating (see Figure C-2). An additional circuit is used to decide whether the converter provides active power or reactive power when loading is high. In most applications active power will be given priority. Hence as the active power is increased, the reactive current capability will decrease, reaching zero as the active power reaches the full rating of the converter. However, in some applications it may be useful to give reactive power priority when voltage drops excessively. This must be done cautiously, because the drop in active power may, through increased line loading, increase line reactive power losses by more than is provided by the converter. In most cases there will be a net gain until the battery power is down to about 75% of converter rating.

The 'outer loop' control is slower, and typically is no more than a desired power level signal received from the system control center. If it is provided by an AGC system, it will be similar to the raise and lower signals sent to generating plants. It may also be just a time clock that 'schedules' the battery charge and discharge times so as to coincide with system peak load and low load periods respectively.

The outer loop may also include a stabilizer. The stabilizer would modulate battery power when oscillations in line power or frequency occur. The battery power will be modulated in step with the oscillations so that it provides damping power. The battery power would oscillate around its power setting until the oscillations subside. If the battery is being discharged or charged at the time of the oscillations, the average battery power will be reduced by the oscillations. Large oscillations which cause battery output to alternate between maximum charge and maximum discharge will reduce battery power to zero until the oscillations subside.

Flicker Control and Momentary Battery Overload

One potential benefit of a battery is its ability to improve power quality through control of voltage. Flicker is one of the most common power quality problems. The word flicker comes from the fact that voltage variations are visible in the output of lighting fixtures. However, while variations in light output are a real problem, variations in voltage also cause malfunctions in computers, electronic process controls, and similar devices that industry depends upon for high production rates and product quality.

A battery converter equipped with a voltage regulator can vary its reactive output rapidly enough to correct most voltage variations that would trouble customers. However, as noted earlier, the converter loading, including real and reactive power, must remain within the converter rating. A modest increase in converter capacity is thus required if reactive power and voltage control are to always be available.

Though increasing the converter rating to allow it to provide reactive power will usually be very cost effective, it may also be feasible to utilize the momentary overload capability of a converter to regulate voltage. Though a converter cannot be overloaded in the usual sense of the word, it will withstand overloads of 120% or more for times of 1 to 2 seconds. The thyristors have little mass, and thus heat up quickly when overloaded. This limits their

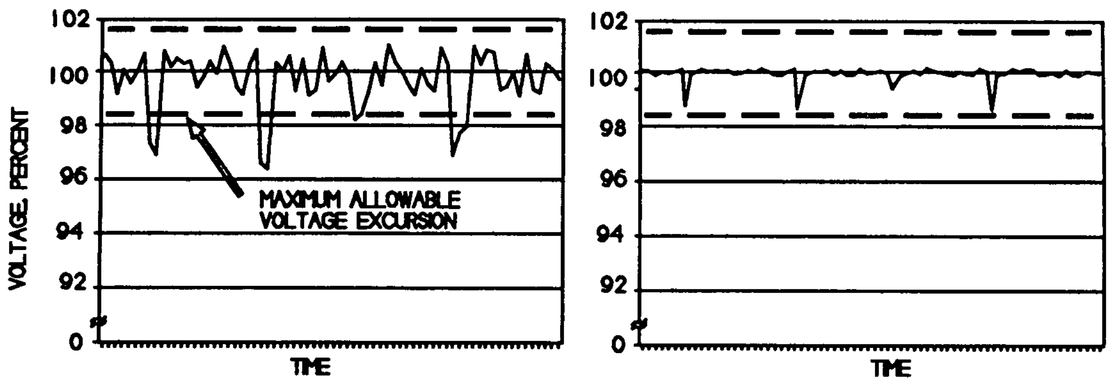


Figure C-5 A battery converter can significantly reduce flicker, thus eliminating one of the most common power quality problems.

inherent overload capability to 1 or 2 seconds. The maximum loading is limited by the ability of the GTO to turn-off current. Overload duration beyond 1 to 2 seconds would require a higher capacity converter (larger or parallel GTOs) or a significant change in the GTO and heat sink design.

Because the duration of most types of flicker is well under one second, the thermal duty caused by exceeding the continuous current limit will be small. A converter may thus be able to control flicker nearly up to the GTO current turn-off limit while operating at or very close to its continuous rating. Figure C-5 shows a typical flicker pattern, and the kind of improvement that the converter could make. Note that the voltage excursion magnitude is reduced modestly, while the duration of the larger excursions is reduced greatly. This is because voltage excursions that cause flicker are usually large rapid changes and the converter cannot change its reactive output instantaneously. However, within a fraction of a cycle, the converter output is changed and restores voltage. Reducing the duration of a voltage excursion is just as effective as reducing its magnitude.

If the converter rating is made somewhat larger than required to deliver the battery rated power, and the extra converter capacity is not used to supply reactive power on a continuous basis, the ability to handle flicker will be larger. The converter can make occasional excursions approaching its current turn-off limit so long as the excursions are short and the accumulated effect on GTO temperature is not excessive. Figure C-6 shows both the increased converter rating to provide reactive power, and the additional momentary operating range that might be provided without exceeding the GTO turn-off current level. Where there will occasionally be a series of voltage excursions over a short period of time, the converter capacity reserved for flicker must account for the accumulative heating from the several excursions.

One type of flicker that has a duration that is usually longer than one second is large motor starting. Large motors can take several seconds to start. The frequency of starting is usually low, however, the duration may exceed the thermal capability of the converter when

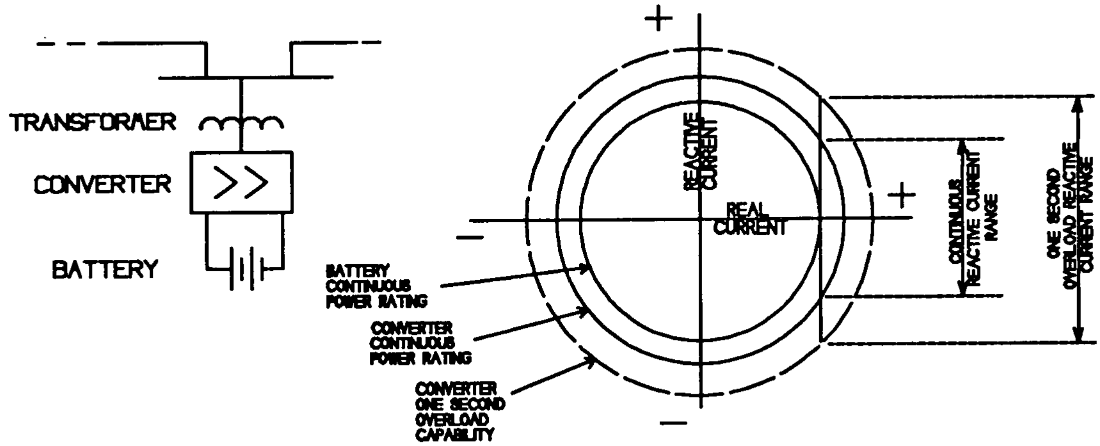


Figure C-6 Battery converters can be sized to provide reactive power and can also endure momentary reactive overload.

it is operating near its continuous rating.

Harmonics

Because the waveform of the converter is not a perfect sinusoid (see Figure C-7a), the converter generates some harmonic current. The harmonic current is caused by the difference between the converter waveform and the system voltage waveform. The difference between the converter voltage and the system voltage (see Figure C-7b) causes a sawtooth current to flow. This sawtooth current can, mathematically, be described as the sum of a collection of sinusoidal currents. Though the converter does not in fact generate the individual harmonic currents (it generates only the sawtooth current), it is convenient to consider it as doing so.

If these currents are excessive, filters can be installed on the ac bus to absorb them locally rather than allow them to flow further into the network. The filters are either an inductor and capacitor in series or simply a capacitor, and provide a low impedance path for the harmonics so they won't flow further into the network. The permissible harmonic levels are detailed in IEEE Standard 519.

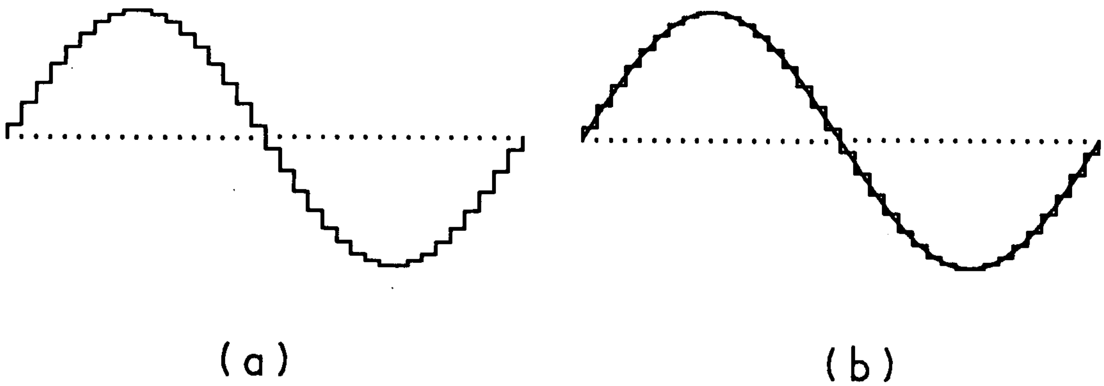


Figure C-7 (a) Waveform generated by a 36 pulse converter.
(b) Comparison of the converter waveform with the normal 60 Hz waveform.

APPENDIX D

MUTUAL EXCLUSIVITY

APPENDIX D

MUTUAL EXCLUSIVITY

As a matter of nomenclature the reader must be careful to observe that battery storage systems and their application to the power system possess certain **attributes** or characteristics. Each of these attributes, individually, or in combination, provides certain **benefits** that may help justify the installation of a battery.

While each of the individual benefits might be the sole economic justification for a battery, typically a battery is going to have to provide several benefits in order to be justified. However, there are instances where operating a battery to provide one benefit will prevent another from being realized. We refer to this condition as a <u>mutual exclusivity.</u>

This means that operators may at times have to pick one benefit or another and operate the battery accordingly. It also means that in battery justification studies we may not be able to give the battery credit for both benefits or may have to discount one of them.

We examine several examples of mutual exclusivity in the following paragraphs:

Transformer Life

Battery storage systems can change the loading pattern of distribution substation transformers. The impact will be:

- reduced loading during the peak load period,
- increased off-peak loading for battery recharging, and
- a higher average loading because of the battery turn-around losses.

The change may occur daily, during certain seasons, or just when there is a local T&D equipment outage. If it occurs often, and changes the loading pattern on transformers, the transformer life may be affected. Considerations and questions may include:

- how often the load pattern is changed,
- how much the maximum transformer hotspot temperature is affected,
- how transformer top oil temperature is affected,

- how much reduced thermal cycling occurs, etc.

It is clear that this is a complex question. Reducing the peak loading may reduce the maximum hotspot temperature and reduce thermal cycling, but it will increase the average transformer temperature. Further, if the load pattern is changed only infrequently, or if the effect on life is just a few years one way or the other, transformer life may not be a significant factor in the battery benefit evaluation.

System Loss Reduction

System loss reduction is fully available only if batteries are *not* used to defer transmission. The load leveling that reduces transmission losses also facilitates transmission deferral, and it is likely that some deferral will occur where batteries are used for load leveling. If transmission is deferred by load leveling, and batteries are spotted in modest sizes to maximize the deferral, average line loading will increase. For modest load leveling and T&D equipment deferral, the loss reduction will be reduced, but will still be positive. However, in the limit, with complete load leveling, every line will be loaded around the clock close to its thermal rating. Only forced and maintenance line outages will limit line loading. And, if batteries are used to backup T&D outages, the loading can be even higher. Under this scenario there will be fewer lines, but average line loading will be very high and losses will be up to about 35% *higher* than without the extensive load leveling from batteries.

Voltage Regulation and Voltage Stability

Though the reactive power available from a battery with a converter rating equal to the battery power rating can provide significant reactive power at intermediate and low active power levels, the benefit may be insignificant if the battery is cycled often and thus spends most of the time at full discharge or full charge power levels (where it cannot provide reactive power).

A battery used primarily for spinning reserve would float much of the time, and could thus provide reactive power. However, because active and reactive power demands may coincide, the reactive power from a nominally rated converter may not be deemed useful.

Spinning Reserve

If a battery is used for load leveling, and is operating at full output, it is not available for spinning reserve. It thus cannot be given credit for load leveling benefits and spinning reserve. On the other hand, if it is operated at partial output, the difference between the operating point and full output is available for spinning reserve. In this case, after a spinning reserve event, there will be less charge left for load leveling.

Some studies have shown that it may be practical to design a battery with an oversized converter so that the battery could occasionally (a few times per year) be discharged at a higher rate and thus provide spinning reserve while providing load leveling. A battery can be discharged over about 1 hour with only modest loss of life, so a "50 MW 4 hour battery" could provide up to 200 MW of spinning reserve for one hour or 100 MW for two hours early when fully charged. If it is used for load leveling at 50 MW, the energy available for spinning reserve would drop as the day progresses.

With flooded cells, the current practice is to discharge the battery routinely only to about a 20% charge level. This type of battery can, however, be discharged fully a few times per year without significant loss of life, and thus can provide about 1 hour of spinning reserve after being "fully discharged" in load leveling service (i.e. a 4 hour battery could provide an extra hour).

The above indicates that there is some room for a battery to provide both spinning reserve and load leveling benefits. However, there is also some potentially significant mutual exclusivity that should be recognized in battery evaluations.

T&D Deferral Versus Generation Benefits

The application of batteries for T&D equipment deferral presents a rather significant opportunity for postponing capital cost expenditures. In this use the battery would be employed to defer the installation of a new line or substation transformer.

However, the mutually exclusive condition arises when this same battery is considered to defer generation, provide generation spinning reserve, or improve economic operation through load leveling. The main question is whether the local peak coincides with the system peak. If it does, discharging a battery during a T&D outage would inherently cover any need for the battery to cover a generation shortage or provide load leveling. Similarly, discharging the battery for reasons associated with the generation would also cover a T&D outage. However, if the local peak occurs after the system peak, the battery might be discharged to cover a generation problem and then be unavailable to cover a T&D problem later (or vice versa if the T&D peak precedes the system peak).

APPENDIX E

TYPES OF LEAD-ACID BATTERIES

APPENDIX E

TYPES OF LEAD-ACID BATTERIES

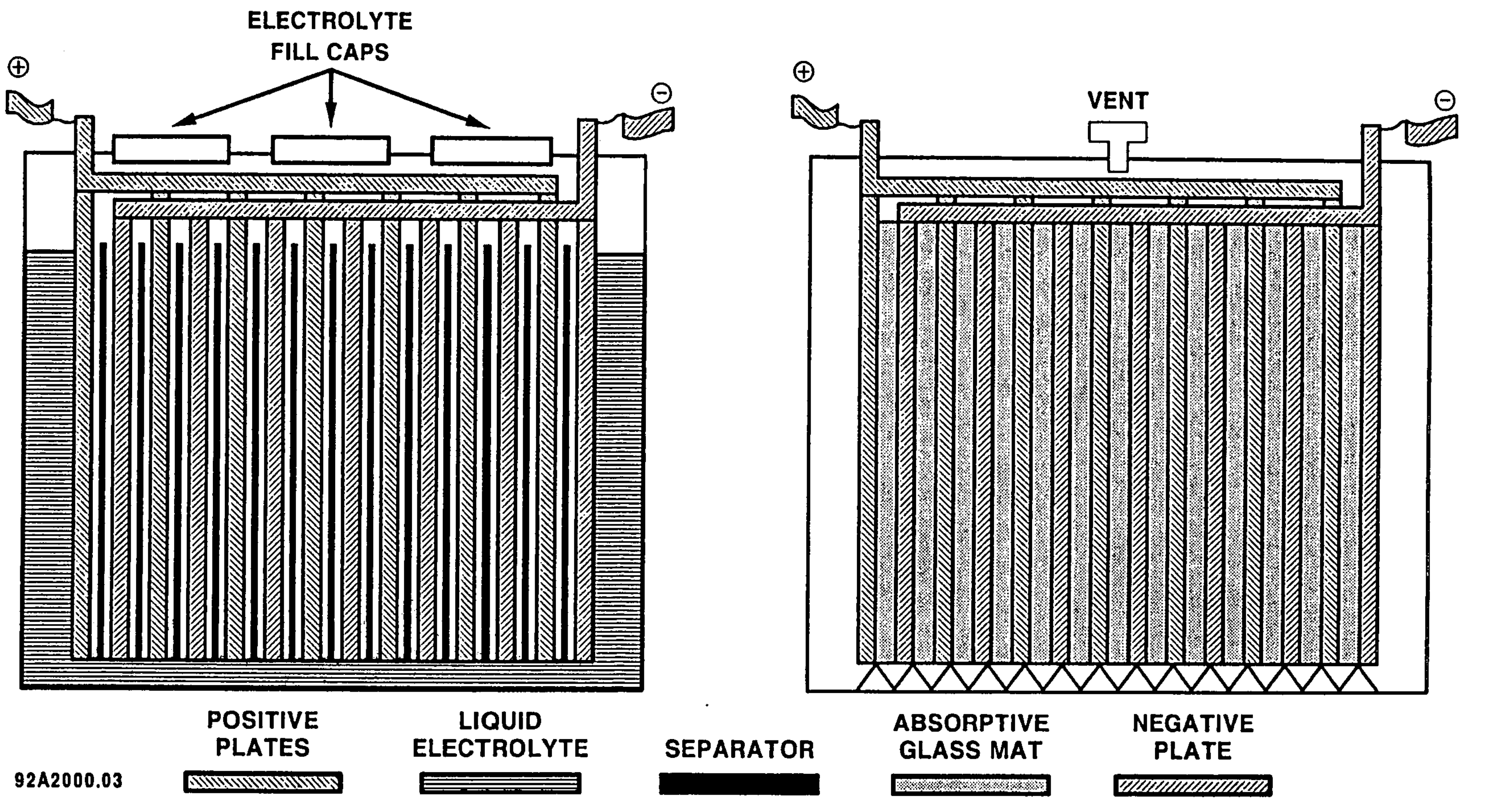
Lead-acid batteries are available in two types: the "flooded-cell" or the "sealed" lead-acid battery, technically described as a "Valve Regulated Lead-Acid" or VRLA battery. The flooded-cell is the oldest and more commonly used lead-acid battery type whereas the VRLA is a more resent derivative of the flooded-cell type.

Flooded-cell batteries contain the electrolyte within their case in liquid form and are commercially available in a wide range of applications in several sizes. Historically, this type of battery has been the preferred choice for utility applications due to its commercial availability. However, due to its flooded-cell design, these batteries require water addition as part of their regular maintenance. In contrast, the electrolyte in the VRLA battery is immobilized either as a "gel" or absorbed in a glass mat between the positive and negative plates of the cell. This allows the battery to be sealed and removes the need for water addition during its operating life. Its sealed construction offers greater flexibility in configuring the layout of the battery energy storage plant while reducing O&M costs.

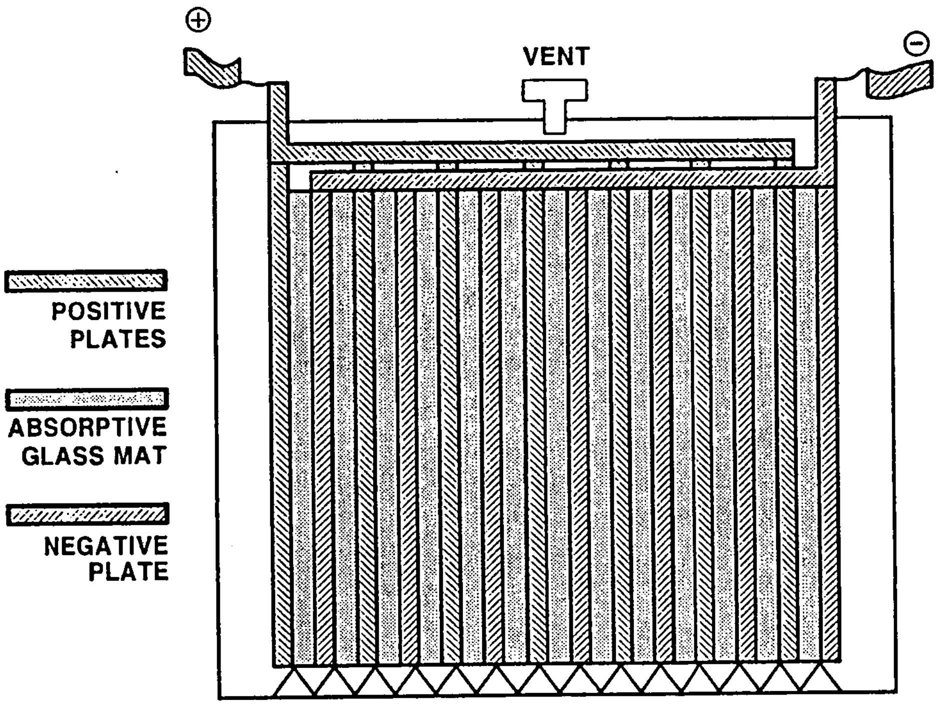
The flooded-cell battery is free to "breath" to the atmosphere through openings in the lid. Appropriate filters and a flash arrestor are installed to capture toxic gasses and hydrogen that are evolved in small quantities during charge/overcharge conditions. The VRLA battery is sealed from the atmosphere and almost all hydrogen and oxygen evolved are trapped inside to recombine and form water that is reused by the battery. However, under some operating conditions gas could be generated faster than it can combine inside the battery. This excess gas is vented to the atmosphere through a one-way valve that operates in the 2 to 5 psi range. Figures x and y show the schematic comparison of flooded and VRLA batteries and the schematic of a VRLA battery.

The 10 MW/40 Mwh battery at Chino, CA, owned by Southern California Edison, as well as the 20 MW/14 Mwh battery recently purchased by Puerto Rico Electric Power Authority are both flooded-cell batteries. The 210 Kw/420 Kwh battery purchased by San Diego Gas & Electric for a commuter trolley peak-shaving demonstration is a VRLA battery and was chosen primarily for its low maintenance and smaller footprint dictated by the limited land available at the site. A comparable flooded-cell battery would not be able to meet either of these requirements.

COMPARISON OF FLOODED-CELL AND VALVE REGULATED LEAD-ACID BATTERIES



VALVE REGULATED LEAD-ACID BATTERY



REACTIONS

$$Pb + PbO_2 + 2H_2SO_4 \underset{\text{CHARGE}}{\overset{\text{DISCHARGE}}{\rightleftharpoons}} 2PbSO_4 + 2H_2O$$

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APPENDIX F

SENSITIVITY ANALYSIS
DETAILED RESULTS

TABLE F1

ESTIMATED VALUE OF BENEFITS AND BATTERY COSTS
FOR
HABERSHAM #8 HOLLYWOOD

ASSUMED BATTERY SIZE= 7,500 KWH ; 5 HRS

YEAR	ANNUAL SAVINGS GENERATION	TRANSMISSION	DISTRIBUTION	BACK-UP/ RELIABILTY CREDIT	TOTAL SAVINGS	NET VALUE $/KWH	ANNUAL BATTERY COST
1997	61,602	0	35,973	138,183	235,758	31	256,573
1998	62,376	0	36,425	144,401	243,203	32	257,737
1999	63,186	0	36,897	150,899	250,982	33	258,954
2000	64,031	0	37,391	157,690	259,113	35	260,226
2001	64,915	0	37,907	164,786	267,608	36	261,554
2002	65,839	0	38,447	172,201	276,487	37	262,943
2003	66,804	0	39,010	179,950	285,765	38	264,394
2004	67,812	0	39,599	188,048	295,460	39	265,910
2005	68,866	0	40,215	196,510	305,591	41	267,495
2006	69,968	0	40,858	205,353	316,179	42	269,150
2007	71,119			214,594	285,713	38	270,881
2008	72,321			224,251	296,572	40	272,689
2009	73,578			234,342	307,920	41	274,579
2010	74,892			244,888	319,779	43	276,553
2011	76,264			255,907	332,172	44	278,617
2012	77,698			267,423	345,122	46	459,260
2013	79,197			279,457	358,655	48	461,131
2014	80,764			292,033	372,796	50	463,087
2015	82,400			305,174	387,575	52	465,130
2016	84,111			318,907	403,018	54	467,266
2017	85,898			333,258	419,156	56	469,497
2018	87,766			348,255	436,021	58	471,829
2019	89,718			363,926	453,644	60	474,266
2020	91,757			380,303	472,060	63	476,812
2021	93,889			397,416	491,305	66	479,474
2022	96,116			415,300	511,416	68	482,254
2023	98,444			433,989	532,432	71	485,160
2024	100,876			453,518	554,394	74	488,197
2025	103,418			473,927	577,344	77	491,370
2026	106,074			495,253	601,327	80	494,687
NET P.V. (1993 $)	667,972	0	206,603	2,058,127	2,932,703	391	2,928,107

Value of Unserved Energy	=	$15.45	/kwh (1993)
Estimated Battery Capital Cost	=	$223	/kWh(1993)
Battery Salvage Value	=	20%	
Battery Shelf Life(Years)	=	15	
Battery O&M	=	0.25%	
Estimated Battery Replacement Cost	=	$178	/kWh(1993)
Estimated PC+BOP Capital Cost	=	$200	/kW(1993)
(a) Generation Capital Deffered	=	$513,742	($1,997)
(b) Transmission Capital Deffered		$0	($1,997)
(c) Distribution Capital Deffered	=	$300,000	($1,997)
Estimated Battery Capital Cost	=	$1,994,487	($1,997)
Estimated PCS+BOP Capital Cost	=	$357,756	($1,997)
Estimated Battery Replacement Cost	=	$3,087,917	($2,012)
Estimated Battery 2nd Replacement Cost	=		
Equivalent 30 Year Life Cost	=	$300	/kWh(1993)
		$1,501	/kW(1993)
BENEFIT/COST RATIO		1.00	

TABLE F2

ESTIMATED VALUE OF BENEFITS AND BATTERY COSTS
FOR
HABERSHAM #8 HOLLYWOOD

ASSUMED BATTERY SIZE= 7,500 KWH ; 5 HRS

YEAR	ANNUAL SAVINGS GENERATION	TRANSMISSION	DISTRIBUTION	BACK-UP/ RELIABILTY CREDIT	TOTAL SAVINGS	NET VALUE $/KWH	ANNUAL BATTERY COST
1997	61,602	0	35,973	138,183	235,758	31	208,896
1998	62,376	0	36,425	144,401	243,203	32	209,870
1999	63,186	0	36,897	150,899	250,982	33	210,888
2000	64,031	0	37,391	157,690	259,113	35	211,951
2001	64,915	0	37,907	164,786	267,608	36	213,063
2002	65,839	0	38,447	172,201	276,487	37	214,224
2003	66,804	0	39,010	179,950	285,765	38	215,438
2004	67,812	0	39,599	188,048	295,460	39	216,707
2005	68,866	0	40,215	196,510	305,591	41	218,032
2006	69,968	0	40,858	205,353	316,179	42	219,417
2007	71,119			214,594	285,713	38	220,865
2008	72,321			224,251	296,572	40	222,377
2009	73,578			234,342	307,920	41	223,958
2010	74,892			244,888	319,779	43	225,610
2011	76,264			255,907	332,172	44	227,336
2012	77,698			267,423	345,122	46	341,194
2013	79,197			279,457	358,655	48	342,839
2014	80,764			292,033	372,796	50	344,558
2015	82,400			305,174	387,575	52	346,355
2016	84,111			318,907	403,018	54	348,232
2017	85,898			333,258	419,156	56	350,194
2018	87,766			348,255	436,021	58	352,244
2019	89,718			363,926	453,644	60	354,386
2020	91,757			380,303	472,060	63	356,625
2021	93,889			397,416	491,305	66	358,964
2022	96,116			415,300	511,416	68	361,409
2023	98,444			433,989	532,432	71	363,964
2024	100,876			453,518	554,394	74	366,633
2025	103,418			473,927	577,344	77	369,423
2026	106,074			495,253	601,327	80	372,338
NET P.V. (1993 $)	667,972	0	206,603	2,058,127	2,932,703	391	2,312,047

Value of Unserved Energy	=	$15.45	/kwh (1993)
Estimated Battery Capital Cost	=	$140	/kWh(1993)
Battery Salvage Value	=	20%	
Battery Shelf Life(Years)	=	15	
Battery O&M	=	0.25%	
Estimated Battery Replacement Cost	=	$112	/kWh(1993)
Estimated PC+BOP Capital Cost	=	$400	/kW(1993)
(a) Generation Capital Deffered	=	$513,742	($1,997)
(b) Transmission Capital Deffered		$0	($1,997)
(c) Distribution Capital Deffered	=	$300,000	($1,997)
Estimated Battery Capital Cost	=	$1,252,145	($1,997)
Estimated PCS+BOP Capital Cost	=	$715,511	($1,997)
Estimated Battery Replacement Cost	=	$1,938,603	($2,012)
Estimated Battery 2nd Replacement Cost	=		
Equivalent 30 Year Life Cost	=	$237	/kWh(1993)
		$1,185	/kW(1993)
BENEFIT/COST RATIO		1.27	

TABLE F3

ESTIMATED VALUE OF BENEFITS AND BATTERY COSTS
FOR
HABERSHAM #8 HOLLYWOOD

ASSUMED BATTERY SIZE= 7,500 KWH ; 5 HRS

YEAR	ANNUAL SAVINGS GENERATION	TRANSMISSION	DISTRIBUTION	BACK-UP/ RELIABILTY CREDIT	TOTAL SAVINGS	NET VALUE $/KWH	ANNUAL BATTERY COST
1997	61,602	0	35,973	138,183	235,758	31	205,551
1998	62,376	0	36,425	144,401	243,203	32	206,348
1999	63,186	0	36,897	150,899	250,982	33	207,181
2000	64,031	0	37,391	157,690	259,113	35	208,051
2001	64,915	0	37,907	164,786	267,608	36	208,961
2002	65,839	0	38,447	172,201	276,487	37	209,911
2003	66,804	0	39,010	179,950	285,765	38	210,904
2004	67,812	0	39,599	188,048	295,460	39	211,942
2005	68,866	0	40,215	196,510	305,591	41	213,026
2006	69,968	0	40,858	205,353	316,179	42	214,160
2007	71,119			214,594	285,713	38	215,349
2008	72,321			224,251	296,572	40	216,587
2009	73,578			234,342	307,920	41	217,880
2010	74,892			244,888	319,779	43	219,231
2011	76,264			255,907	332,172	44	220,644
2012	77,698			267,423	345,122	46	250,613
2013	79,197			279,457	358,655	48	251,725
2014	80,764			292,033	372,796	50	252,888
2015	82,400			305,174	387,575	52	254,103
2016	84,111			318,907	403,018	54	255,373
2017	85,898			333,258	419,156	56	256,700
2018	87,766			348,255	436,021	58	258,087
2019	89,718			363,926	453,644	60	259,536
2020	91,757			380,303	472,060	63	261,050
2021	93,889			397,416	491,305	66	262,633
2022	96,116			415,300	511,416	68	264,286
2023	98,444			433,989	532,432	71	266,014
2024	100,876			453,518	554,394	74	267,820
2025	103,418			473,927	577,344	77	269,707
2026	106,074			495,253	601,327	80	271,679
NET P.V. (1993 $)	667,972		206,603	2,058,127	2,932,703	391	2,064,314

Value of Unserved Energy	=	$15.45	/kwh (1993)
Estimated Battery Capital Cost	=	140	/kWh(1993)
Battery Salvage Value	=	20%	
Battery Shelf Life(Years)	=	10	
Battery O&M	=	0.25%	
Estimated Battery Replacement Cost	=	112	/kWh(1993)
Estimated PC+BOP Capital Cost	=	200	/kW(1993)
(a) Generation Capital Deffered	=	$513,742	($1,997)
(b) Transmission Capital Deffered		$0	($1,997)
(c) Distribution Capital Deffered	=	$300,000	($1,997)
Estimated Battery Capital Cost	=	$1,252,145	($1,997)
Estimated PCS+BOP Capital Cost	=	$357,756	($1,997)
Estimated Battery Replacement Cost	=	$1,555,634	($2,007)
Estimated Battery 2nd Replacement Cost	=	$2,415,852	($2,017)
Equivalent 30 Year Life Cost	=	$212	/kWh(1993)
		$1,058	/kW(1993)
BENEFIT/COST RATIO		1.42	

TABLE F4

ESTIMATED VALUE OF BENEFITS AND BATTERY COSTS
FOR
HABERSHAM #8 HOLLYWOOD

ASSUMED BATTERY SIZE= 7,500 KWH ; 5 HRS

YEAR	ANNUAL SAVINGS GENERATION	TRANSMISSION	DISTRIBUTION	BACK-UP/ RELIABILTY CREDIT	TOTAL SAVINGS	NET VALUE $/KWH	ANNUAL BATTERY COST
1997	61,602	0	35,973	138,183	235,758	31	155,766
1998	62,376	0	36,425	144,401	243,203	32	156,563
1999	63,186	0	36,897	150,899	250,982	33	157,396
2000	64,031	0	37,391	157,690	259,113	35	158,266
2001	64,915	0	37,907	164,786	267,608	36	159,175
2002	65,839	0	38,447	172,201	276,487	37	160,125
2003	66,804	0	39,010	179,950	285,765	38	161,119
2004	67,812	0	39,599	188,048	295,460	39	162,156
2005	68,866	0	40,215	196,510	305,591	41	163,241
2006	69,968	0	40,858	205,353	316,179	42	164,374
2007	71,119			214,594	285,713	38	165,558
2008	72,321			224,251	296,572	40	166,796
2009	73,578			234,342	307,920	41	168,089
2010	74,892			244,888	319,779	43	169,441
2011	76,264			255,907	332,172	44	170,853
2012	77,698			267,423	345,122	46	262,031
2013	79,197			279,457	358,655	48	263,094
2014	80,764			292,033	372,796	50	264,204
2015	82,400			305,174	387,575	52	265,364
2016	84,111			318,907	403,018	54	266,576
2017	85,898			333,258	419,156	56	267,843
2018	87,766			348,255	436,021	58	269,167
2019	89,718			363,926	453,644	60	270,551
2020	91,757			380,303	472,060	63	271,997
2021	93,889			397,416	491,305	66	273,508
2022	96,116			415,300	511,416	68	275,086
2023	98,444			433,989	532,432	71	276,736
2024	100,876			453,518	554,394	74	278,461
2025	103,418			473,927	577,344	77	280,262
2026	106,074			495,253	601,327	80	282,145
NET P.V. (1993 $)	667,972	0	206,603	2,058,127	2,932,703	391	1,742,261

Value of Unserved Energy	=	$15.45	/kwh (1993)
Estimated Battery Capital Cost	=	$140	/kWh(1993)
Battery Salvage Value	=	40%	
Battery Shelf Life(Years)	=	15	
Battery O&M	=	0.25%	
Estimated Battery Replacement Cost	=	$84	/kWh(1993)
Estimated PC+BOP Capital Cost	=	$200	/kW(1993)
(a) Generation Capital Deffered	=	$513,742	($1,997)
(b) Transmission Capital Deffered		$0	($1,997)
(c) Distribution Capital Deffered	=	$300,000	($1,997)
Estimated Battery Capital Cost	=	$1,252,145	($1,997)
Estimated PCS+BOP Capital Cost	=	$357,756	($1,997)
Estimated Battery Replacement Cost	=	$1,453,952	($2,012)
Estimated Battery 2nd Replacement Cost	=		
Equivalent 30 Year Life Cost	=	$179	/kWh(1993)
		$893	/kW(1993)
BENEFIT/COST RATIO		1.68	

TABLE F5

ESTIMATED VALUE OF BENEFITS AND BATTERY COSTS
FOR
HABERSHAM #8 HOLLYWOOD

ASSUMED BATTERY SIZE= 7,500 KWH ; 5 HRS

YEAR	ANNUAL SAVINGS GENERATION	TRANSMISSION	DISTRIBUTION	BACK-UP/ RELIABILTY CREDIT	TOTAL SAVINGS	NET VALUE $/KWH	ANNUAL BATTERY COST
1997	61,602	0	35,973	73,787	171,362	23	174,048
1998	62,376	0	36,425	77,108	175,909	23	174,845
1999	63,186	0	36,897	80,577	180,660	24	175,677
2000	64,031	0	37,391	84,203	185,626	25	176,548
2001	64,915	0	37,907	87,992	190,815	25	177,457
2002	65,839	0	38,447	91,952	196,238	26	178,407
2003	66,804	0	39,010	96,090	201,904	27	179,400
2004	67,812	0	39,599	100,414	207,826	28	180,438
2005	68,866	0	40,215	104,933	214,014	29	181,523
2006	69,968	0	40,858	109,655	220,480	29	182,656
2007	71,119			114,589	185,708	25	183,840
2008	72,321			119,746	192,067	26	185,078
2009	73,578			125,134	198,712	26	186,371
2010	74,892			130,765	205,657	27	187,722
2011	76,264			136,650	212,914	28	189,135
2012	77,698			142,799	220,497	29	302,665
2013	79,197			149,225	228,422	30	303,968
2014	80,764			155,940	236,703	32	305,328
2015	82,400			162,957	245,357	33	306,751
2016	84,111			170,290	254,401	34	308,237
2017	85,898			177,953	263,851	35	309,790
2018	87,766			185,961	273,727	36	311,413
2019	89,718			194,330	284,047	38	313,109
2020	91,757			203,074	294,832	39	314,881
2021	93,889			212,213	306,101	41	316,733
2022	96,116			221,762	317,878	42	318,668
2023	98,444			231,742	330,185	44	320,691
2024	100,876			242,170	343,046	46	322,804
2025	103,418			253,068	356,485	48	325,013
2026	106,074			264,456	370,530	49	327,321
NET P.V. (1993 $)	667,972	0	206,603	1,099,000	1,973,575	263	1,966,781

Value of Unserved Energy	=	$8.25	/kwh (1993)
Estimated Battery Capital Cost	=	$140	/kWh(1993)
Battery Salvage Value	=	20%	
Battery Shelf Life(Years)	=	15	
Battery O&M	=	0.25%	
Estimated Battery Replacement Cost	=	$112	/kWh(1993)
Estimated PC+BOP Capital Cost	=	$200	/kW(1993)
(a) Generation Capital Deffered	=	$513,742	($1,997)
(b) Transmission Capital Deffered		$0	($1,997)
(c) Distribution Capital Deffered	=	$300,000	($1,997)
Estimated Battery Capital Cost	=	$1,252,145	($1,997)
Estimated PCS+BOP Capital Cost	=	$357,756	($1,997)
Estimated Battery Replacement Cost	=	$1,938,603	($2,012)
Estimated Battery 2nd Replacement Cost	=		
Equivalent 30 Year Life Cost	=	$202	/kWh(1993)
		$1,008	/kW(1993)
BENEFIT/COST RATIO		1.00	

TABLE F6

ESTIMATED VALUE OF BENEFITS AND BATTERY COSTS
FOR
HABERSHAM #8 HOLLYWOOD

ASSUMED BATTERY SIZE= 7,500 KWH ; 5 HRS

YEAR	ANNUAL SAVINGS GENERATION	TRANSMISSION	DISTRIBUTION	BACK-UP/ RELIABILTY CREDIT	TOTAL SAVINGS	NET VALUE $/KWH	ANNUAL BATTERY COST
1997	61,602	0	35,973	138,183	235,758	31	174,048
1998	62,376	0	36,425	144,401	243,203	32	174,845
1999	63,186	0	36,897	150,899	250,982	33	175,677
2000	64,031	0	37,391	157,690	259,113	35	176,548
2001	64,915	0	37,907	164,786	267,608	36	177,457
2002	65,839	0	38,447	172,201	276,487	37	178,407
2003	66,804	0	39,010	179,950	285,765	38	179,400
2004	67,812	0	39,599	188,048	295,460	39	180,438
2005	68,866	0	40,215	196,510	305,591	41	181,523
2006	69,968	0	40,858	205,353	316,179	42	182,656
2007	71,119		41,530	214,594	327,243	44	183,840
2008	72,321		42,232	224,251	338,805	45	185,078
2009	73,578		42,966	234,342	350,887	47	186,371
2010	74,892		43,733	244,888	363,512	48	187,722
2011	76,264		44,535	255,907	376,706	50	189,135
2012	77,698		45,372	267,423	390,494	52	302,665
2013	79,197		46,247	279,457	404,902	54	303,968
2014	80,764		47,162	292,033	419,958	56	305,328
2015	82,400		48,118	305,174	435,692	58	306,751
2016	84,111		49,117	318,907	452,134	60	308,237
2017	85,898		50,160	333,258	469,316	63	309,790
2018	87,766		51,251	348,255	487,271	65	311,413
2019	89,718		52,391	363,926	506,035	67	313,109
2020	91,757		53,582	380,303	525,642	70	314,881
2021	93,889		54,826	397,416	546,132	73	316,733
2022	96,116		56,127	415,300	567,544	76	318,668
2023	98,444		57,486	433,989	589,919	79	320,691
2024	100,876		58,907	453,518	613,301	82	322,804
2025	103,418		60,391	473,927	637,735	85	325,013
2026	106,074		61,942	495,253	663,269	88	327,321
NET P.V. (1993 $)	667,972	0	390,063	2,058,127	3,116,162	415	1,966,781

Value of Unserved Energy	=	$15.45	/kwh (1993)
Estimated Battery Capital Cost	=	$140	/kWh(1993)
Battery Salvage Value	=	20%	
Battery Shelf Life(Years)	=	15	
Battery O&M	=	0.25%	
Estimated Battery Replacement Cost	=	$112	/kWh(1993)
Estimated PC+BOP Capital Cost	=	$200	/kW(1993)
(a) Generation Capital Deffered	=	$513,742	($1,997)
(b) Transmission Capital Deffered		$0	($1,997)
(c) Distribution Capital Deffered	=	$300,000	($1,997)
Estimated Battery Capital Cost	=	$1,252,145	($1,997)
Estimated PCS+BOP Capital Cost	=	$357,756	($1,997)
Estimated Battery Replacement Cost	=	$1,938,603	($2,012)
Estimated Battery 2nd Replacement Cost	=		
Equivalent 30 Year Life Cost	=	$202	/kWh(1993)
		$1,008	/kW(1993)
BENEFIT/COST RATIO		1.58	

TABLE F7

ESTIMATED VALUE OF BENEFITS AND BATTERY COSTS
FOR
HABERSHAM #8 HOLLYWOOD

ASSUMED BATTERY SIZE= 7,500 KWH ; 5 HRS

YEAR	ANNUAL SAVINGS GENERATION	ANNUAL SAVINGS TRANSMISSION	ANNUAL SAVINGS DISTRIBUTION	BACK-UP/ RELIABILTY CREDIT	TOTAL SAVINGS	NET VALUE $/KWH	ANNUAL BATTERY COST
1997	61,602	0	35,973	73,787	171,362	23	298,208
1998	62,376	0	36,425	77,108	175,909	23	299,549
1999	63,186	0	36,897	80,577	180,660	24	300,951
2000	64,031	0	37,391	84,203	185,626	25	302,416
2001	64,915	0	37,907	87,992	190,815	25	303,947
2002	65,839	0	38,447	91,952	196,238	26	305,546
2003	66,804	0	39,010	96,090	201,904	27	307,218
2004	67,812	0	39,599	100,414	207,826	28	308,965
2005	68,866	0	40,215	104,933	214,014	29	310,790
2006	69,968	0	40,858	109,655	220,480	29	312,698
2007	71,119		41,530	114,589	227,238	30	314,724
2008	72,321		42,232	119,746	234,299	31	316,807
2009	73,578		42,966	125,134	241,679	32	318,984
2010	74,892		43,733	130,765	249,390	33	321,259
2011	76,264		44,535	136,650	257,448	34	323,636
2012	77,698		45,372	142,799	265,869	35	290,010
2013	79,197		46,247	149,225	274,669	37	291,616
2014	80,764		47,162	155,940	283,865	38	293,293
2015	82,400		48,118	162,957	293,475	39	295,046
2016	84,111		49,117	170,290	303,517	40	296,878
2017	85,898		50,160	177,953	314,012	42	298,793
2018	87,766		51,251	185,961	324,978	43	300,793
2019	89,718		52,391	194,330	336,438	45	302,884
2020	91,757		53,582	203,074	348,413	46	305,068
2021	93,889		54,826	212,213	360,928	48	307,351
2022	96,116		56,127	221,762	374,006	50	309,737
2023	98,444		57,486	231,742	387,672	52	312,230
2024	100,876		58,907	242,170	401,953	54	314,835
2025	103,418		60,391	253,068	416,876	56	317,558
2026	106,074		61,942	264,456	432,472	58	320,403
NET P.V. (1993 $)	667,972		390,063	1,099,000	2,157,035	288	2,834,731

Value of Unserved Energy	=	$8.25	/kwh (1993)
Estimated Battery Capital Cost	=	223	/kWh(1993)
Battery Salvage Value	=	40%	
Battery Shelf Life(Years)	=	10	
Battery O&M	=	0.25%	
Estimated Battery Replacement Cost	=	133.8	/kWh(1993)
Estimated PC+BOP Capital Cost	=	400	/kW(1993)
(a) Generation Capital Deffered	=	$513,742	($1,997)
(b) Transmission Capital Deffered		$0	($1,997)
(c) Distribution Capital Deffered	=	$300,000	($1,997)
Estimated Battery Capital Cost	=	$1,994,487	($1,997)
Estimated PCS+BOP Capital Cost	=	$715,511	($1,997)
Estimated Battery Replacement Cost	=	$1,858,427	($2,007)
Estimated Battery 2nd Replacement Cost	=	$2,886,060	($2,017)
Equivalent 30 Year Life Cost	=	$291	/kWh(1993)
		$1,453	/kW(1993)
BENEFIT/COST RATIO		0.76	

TABLE F8

ESTIMATED VALUE OF BENEFITS AND BATTERY STORAGE COSTS
FOR
PLANTERS #9 EGYPT

ASSUMED BATTERY SIZE= 22,000 KWH ; 4 HOURS

YEAR	ANNUAL SAVINGS GENERATION	TRANSMISSION	DISTRIBUTION	BACK-UP/ RELIABILTY CREDIT	TOTAL SAVINGS	NET VALUE $/KWH	ANNUAL BATTERY COST
1997	180,699	640,252	0	26,235	847,187	39	536,095
1998	182,971	648,301	0	27,416	858,688	39	538,563
1999	185,345	656,713	0	28,650	870,707	40	541,141
2000	187,826	665,503	0	29,939	883,268	40	543,836
2001	190,418	674,689	0	31,286	896,393	41	546,651
2002	193,127	684,288		32,694	910,109	41	549,594
2003	195,958	694,318		34,165	924,442	42	552,669
2004	198,917	704,801		35,703	939,420	43	555,882
2005	202,008	715,755		37,309	955,072	43	559,240
2006	205,239	727,202		38,988	971,429	44	562,749
2007	208,615			40,743	249,358	11	566,416
2008	212,143			42,576	254,719	12	570,247
2009	215,830			44,492	260,322	12	574,252
2010	219,682			46,494	266,177	12	578,436
2011	223,708			48,587	272,295	12	582,809
2012	227,916			50,773	278,688	13	916,073
2013	232,312			53,058	285,370	13	920,144
2014	236,906			55,445	292,352	13	924,399
2015	241,707			57,940	299,648	14	928,845
2016	246,725			60,548	307,272	14	933,491
2017	251,968			63,272	315,240	14	938,346
2018	257,446			66,120	323,566	15	943,420
2019	263,172			69,095	332,267	15	948,722
2020	269,155			72,204	341,359	16	954,263
2021	275,407			75,453	350,860	16	960,053
2022	281,941			78,849	360,790	16	966,104
2023	288,768			82,397	371,165	17	972,427
2024	295,903			86,105	382,008	17	979,034
2025	303,359			89,980	393,339	18	985,939
2026	311,151			94,029	405,179	18	993,154
NET P.V. (1993 $)	1,959,385	3,677,200	0	390,756	6,027,341	274	6,022,418

Value of Unserved Energy	=	$1.00	/kwh (1993)
Estimated Battery Capital Cost	=	$140	/kWh(1993)
Battery Salvage Value	=	20%	
Battery Shelf Life(Years)	=	15	
Battery O&M	=	0.25%	
Estimated Battery Replacement Cost	=	$112	/kWh(1993)
Estimated PC+BOP Capital Cost	=	$200	/kW(1993)
(a) Generation Capital Deffered	=	$1,506,975	($1,997)
(b) Transmission Capital Deffered		$5,339,510	($1,997)
(c) Distribution Capital Deffered	=	$0	($1,997)
Estimated Battery Capital Cost	=	$3,672,957	($1,997)
Estimated PCS+BOP Capital Cost	=	$1,311,770	($1,997)
Estimated Battery Replacement Cost	=	$5,686,568	($2,012)
Estimated Battery 2nd Replacement Cost	=		
Equivalent 30 Year Life Cost	=	$211	/kWh(1993)
		$842	/kW(1993)
BENEFIT/COST RATIO		1.00	

TABLE F9

ESTIMATED VALUE OF BENEFITS AND BATTERY STORAGE COSTS
FOR
PLANTERS #9 EGYPT

ASSUMED BATTERY SIZE= 22,000 KWH ; 4 HOURS

YEAR	ANNUAL SAVINGS GENERATION	TRANSMISSION	DISTRIBUTION	BACK-UP/ RELIABILTY CREDIT	TOTAL SAVINGS	NET VALUE $/KWH	ANNUAL BATTERY COST
1997	180,699	640,252	0	131,177	952,128	43	536,095
1998	182,971	648,301	0	137,080	968,352	44	538,563
1999	185,345	656,713	0	143,249	985,306	45	541,141
2000	187,826	665,503	0	149,695	1,003,023	46	543,836
2001	190,418	674,689	0	156,431	1,021,538	46	546,651
2002	193,127	684,288		163,470	1,040,885	47	549,594
2003	195,958	694,318		170,827	1,061,103	48	552,669
2004	198,917	704,801		178,514	1,082,231	49	555,882
2005	202,008	715,755		186,547	1,104,310	50	559,240
2006	205,239	727,202		194,942	1,127,382	51	562,749
2007	208,615	739,164		203,714	1,151,493	52	566,416
2008	212,143	751,664		212,881	1,176,688	53	570,247
2009	215,830	764,727		222,461	1,203,017	55	574,252
2010	219,682	778,378		232,471	1,230,531	56	578,436
2011	223,708	792,643		242,933	1,259,284	57	582,809
2012	227,916	807,549		253,865	1,289,330	59	916,073
2013	232,312	823,127		265,289	1,320,728	60	920,144
2014	236,906	839,406		277,227	1,353,539	62	924,399
2015	241,707	856,417		289,702	1,387,826	63	928,845
2016	246,725	874,194		302,738	1,423,657	65	933,491
2017	251,968	892,770		316,362	1,461,100	66	938,346
2018	257,446	912,183		330,598	1,500,227	68	943,420
2019	263,172	932,469		345,475	1,541,116	70	948,722
2020	269,155	953,668		361,021	1,583,844	72	954,263
2021	275,407	975,821		377,267	1,628,496	74	960,053
2022	281,941	998,971		394,244	1,675,156	76	966,104
2023	288,768	1,023,163		411,985	1,723,916	78	972,427
2024	295,903	1,048,443		430,524	1,774,871	81	979,034
2025	303,359	1,074,861		449,898	1,828,118	83	985,939
2026	311,151	1,102,468		470,143	1,883,762	86	993,154
NET P.V. (1993 $)	1,959,385	6,942,484	0	1,953,778	**********	493	6,022,418

Value of Unserved Energy	=	$5.00	/kwh (1993)
Estimated Battery Capital Cost	=	$140	/kWh(1993)
Battery Salvage Value	=	20%	
Battery Shelf Life(Years)	=	15	
Battery O&M	=	0.25%	
Estimated Battery Replacement Cost	=	$112	/kWh(1993)
Estimated PC+BOP Capital Cost	=	$200	/kW(1993)
(a) Generation Capital Deffered	=	$1,506,975	($1,997)
(b) Transmission Capital Deffered		$5,339,510	($1,997)
(c) Distribution Capital Deffered	=	$0	($1,997)
Estimated Battery Capital Cost	=	$3,672,957	($1,997)
Estimated PCS+BOP Capital Cost	=	$1,311,770	($1,997)
Estimated Battery Replacement Cost	=	$5,686,568	($2,012)
Estimated Battery 2nd Replacement Cost	=		
Equivalent 30 Year Life Cost	=	$211	/kWh(1993)
		$842	/kW(1993)
BENEFIT/COST RATIO		1.80	

TABLE F10

ESTIMATED VALUE OF BENEFITS AND BATTERY STORAGE COSTS
FOR
SATILLA #12 LANES BRIDGE

ASSUMED BATTERY SIZE = 9,000 KWH ; 6 HOURS

YEAR	ANNUAL SAVINGS GENERATION	TRANSMISSION	DISTRIBUTION	BACK-UP/ RELIABILTY CREDIT	TOTAL SAVINGS	NET VALUE $/KWH	ANNUAL BATTERY COST
1997	73,922	0	35,973	85,861	195,756	22	201,887
1998	74,852	0	36,425	89,725	201,002	22	202,808
1999	75,823	0	36,897	93,763	206,483	23	203,771
2000	76,838	0	37,391	97,982	212,211	24	204,776
2001	77,898	0	37,907	102,391	218,197	24	205,827
2002	79,007	0	38,447	106,999	224,452	25	206,925
2003	80,165	0	39,010	111,814	230,989	26	208,073
2004	81,375	0	39,599	116,845	237,820	26	209,272
2005	82,640	0	40,215	122,103	244,958	27	210,525
2006	83,961	0	40,858	127,598	252,417	28	211,835
2007	85,342	0		133,340	218,683	24	213,203
2008	86,786	0		139,340	226,126	25	214,633
2009	88,294	0		145,611	233,905	26	216,128
2010	89,870	0		152,163	242,033	27	217,689
2011	91,517	0		159,010	250,528	28	219,321
2012	93,238	0		166,166	259,404	29	355,492
2013	95,037	0		173,643	268,680	30	356,987
2014	96,916	0		181,457	278,374	31	358,548
2015	98,880	0		189,623	288,503	32	360,180
2016	100,933	0		198,156	299,089	33	361,885
2017	103,078	0		207,073	310,151	34	363,667
2018	105,319	0		216,391	321,710	36	365,529
2019	107,661	0		226,129	333,790	37	367,475
2020	110,109	0		236,305	346,413	38	369,509
2021	112,667	0		246,938	359,605	40	371,633
2022	115,339	0		258,051	373,390	41	373,854
2023	118,133	0		269,663	387,795	43	376,175
2024	121,051	0		281,798	402,849	45	378,600
2025	124,101	0		294,479	418,580	47	381,134
2026	127,289	0		307,730	435,019	48	383,782
NET P.V. (1993 $)	801,566	0	206,603	1,278,836	2,287,006	254	2,291,083

Value of Unserved Energy	=	$8.00	/kwh (1993)
Estimated Battery Capital Cost	=	$140	/kWh(1993)
Battery Salvage Value	=	20%	
Battery Shelf Life(Years)	=	15	
Battery O&M	=	0.25%	
Estimated Battery Replacement Cost	=	$112	/kWh(1993)
Estimated PC+BOP Capital Cost	=	$200	/kW(1993)
(a) Generation Capital Deffered	=	$616,490	($1,997)
(b) Transmission Capital Deffered	=	$0	($1,997)
(c) Distribution Capital Deffered	=	$300,000	($1,997)
Estimated Battery Capital Cost		$1,502,573	($1,997)
Estimated PCS+BOP Capital Cost	=	$357,756	($1,997)
Estimated Battery Replacement Cost	=	$2,326,323	($2,012)
Estimated Battery 2nd Replacement Cost	=		
Equivalent 30 Year Life Cost	=	$196	/kWh(1993)
		$1,175	/kW(1993)
BENEFIT/COST RATIO	=	1.00	

TABLE F11

ESTIMATED VALUE OF BENEFITS AND BATTERY STORAGE COSTS
FOR VIDALIA

ASSUMED BATTERY SIZE= 217,000 KWH ; 7 HOURS

YEAR	ANNUAL SAVINGS GENERATION	TRANSMISSION	DISTRIBUTION	BACK-UP/ RELIABILTY CREDIT	TOTAL SAVINGS	NET VALUE $/KWH	ANNUAL BATTERY COST
1997	1,782,349	434,068	35,973	2,225,478	4,477,869	21	4,747,698
1998	1,804,757	439,526	36,425	2,325,625	4,606,332	21	4,769,291
1999	1,828,173	445,228	36,897	2,430,278	4,740,577	22	4,791,856
2000	1,852,643	451,188	37,391	2,539,640	4,880,863	22	4,815,436
2001	1,878,215	457,415	37,907	2,653,924	5,027,461	23	4,840,077
2002	1,904,936		38,447	2,773,351	4,716,734	22	4,865,827
2003	1,932,861		39,010	2,898,152	4,870,022	22	4,892,736
2004	1,962,041		39,599	3,028,568	5,030,209	23	4,920,856
2005	1,992,535		40,215	3,164,854	5,197,604	24	4,950,241
2006	2,024,402		40,858	3,307,272	5,372,532	25	4,980,949
2007	2,057,702			3,456,100	5,513,802	25	5,013,038
2008	2,092,501			3,611,624	5,704,125	26	5,046,571
2009	2,128,865			3,774,147	5,903,013	27	5,081,614
2010	2,166,866			3,943,984	6,110,850	28	5,118,233
2011	2,206,578			4,121,463	6,328,041	29	5,156,500
2012	2,248,076			4,306,929	6,555,005	30	8,438,607
2013	2,291,441			4,500,741	6,792,182	31	8,473,454
2014	2,336,758			4,703,274	7,040,032	32	8,509,870
2015	2,384,115			4,914,921	7,299,036	34	8,547,924
2016	2,433,602			5,136,093	7,569,695	35	8,587,691
2017	2,485,316			5,367,217	7,852,533	36	8,629,247
2018	2,539,357			5,608,742	8,148,099	38	8,672,674
2019	2,595,831			5,861,135	8,456,966	39	8,718,054
2020	2,654,845			6,124,886	8,779,731	40	8,765,477
2021	2,716,515			6,400,506	9,117,022	42	8,815,033
2022	2,780,961			6,688,529	9,469,490	44	8,866,820
2023	2,848,306			6,989,513	9,837,819	45	8,920,937
2024	2,918,682			7,304,041	10,222,723	47	8,977,490
2025	2,992,225			7,632,723	10,624,947	49	9,036,587
2026	3,069,077			7,976,195	11,045,272	51	9,098,343
NET P.V. (1993 $)	19,326,656	1,432,366	206,603	33,146,731	54,112,356	249	54,051,315

Value of Unserved Energy	=	$8.60	/kwh (1993)
Estimated Battery Capital Cost	=	$140	/kWh(1993)
Battery Salvage Value	=	20%	
Battery Shelf Life(Years)	=	15	
Battery O&M	=	0.25%	
Estimated Battery Replacement Cost		$112	/kWh(1993)
Estimated PC+BOP Capital Cost		$200	/kW(1993)
(a) Generation Capital Deffered		$14,864,258	($1,997)
(b) Transmission Capital Deffered		$3,620,000	($1,997)
(c) Distribution Capital Deffered		$300,000	($1,997)
Estimated Battery Capital Cost		$36,228,715	($1,997)
Estimated PCS+BOP Capital Cost	=	$7,393,615	($1,997)
Estimated Battery Replacement Cost	=	$56,090,237	($2,012)
Estimated Battery 2nd Replacement Cost	=		
Equivalent 30 Year Life Cost	=	$192	/kWh(1993)
		$1,341	/kW(1993)
BENEFIT/COST RATIO		1.00	

TABLE F12

ESTIMATED VALUE OF BENEFITS AND BATTERY STORAGE COSTS
FOR VIDALIA

ASSUMED BATTERY SIZE= 217,000 KWH ; 7 HOURS

YEAR	ANNUAL SAVINGS GENERATION	TRANSMISSION	DISTRIBUTION	BACK-UP/ RELIABILTY CREDIT	TOTAL SAVINGS	NET VALUE $/KWH	ANNUAL BATTERY COST
1997	1,782,349	434,068	35,973	646,941	2,899,332	13	4,747,698
1998	1,804,757	439,526	36,425	676,054	2,956,761	14	4,769,291
1999	1,828,173	445,228	36,897	706,476	3,016,775	14	4,791,856
2000	1,852,643	451,188	37,391	738,268	3,079,490	14	4,815,436
2001	1,878,215	457,415	37,907	771,490	3,145,027	14	4,840,077
2002	1,904,936	463,923	38,447	806,207	3,213,512	15	4,865,827
2003	1,932,861	470,724	39,010	842,486	3,285,080	15	4,892,736
2004	1,962,041	477,830	39,599	880,398	3,359,869	15	4,920,856
2005	1,992,535	485,257	40,215	920,016	3,438,022	16	4,950,241
2006	2,024,402	493,017	40,858	961,416	3,519,693	16	4,980,949
2007	2,057,702	501,127	41,530	1,004,680	3,605,039	17	5,013,038
2008	2,092,501	509,602	42,232	1,049,891	3,694,225	17	5,046,571
2009	2,128,865	518,458	42,966	1,097,136	3,787,425	17	5,081,614
2010	2,166,866	527,713	43,733	1,146,507	3,884,819	18	5,118,233
2011	2,206,578	537,384	44,535	1,198,100	3,986,596	18	5,156,500
2012	2,248,076	547,490	45,372	1,252,014	4,092,952	19	8,438,607
2013	2,291,441	558,051	46,247	1,308,355	4,204,095	19	8,473,454
2014	2,336,758	569,088	47,162	1,367,231	4,320,239	20	8,509,870
2015	2,384,115	580,621	48,118	1,428,756	4,441,609	20	8,547,924
2016	2,433,602	592,673	49,117	1,493,050	4,568,441	21	8,587,691
2017	2,485,316	605,267	50,160	1,560,238	4,700,981	22	8,629,247
2018	2,539,357	618,428	51,251	1,630,448	4,839,485	22	8,672,674
2019	2,595,831	632,181	52,391	1,703,818	4,984,221	23	8,718,054
2020	2,654,845	646,554	53,582	1,780,490	5,135,471	24	8,765,477
2021	2,716,515	661,573	54,826	1,860,612	5,293,527	24	8,815,033
2022	2,780,961	677,267	56,127	1,944,340	5,458,695	25	8,866,820
2023	2,848,306	693,669	57,486	2,031,835	5,631,296	26	8,920,937
2024	2,918,682	710,808	58,907	2,123,268	5,811,664	27	8,977,490
2025	2,992,225	728,718	60,391	2,218,815	6,000,149	28	9,036,587
2026	3,069,077	747,435	61,942	2,318,661	6,197,115	29	9,098,343
NET P.V. (1993 $)	19,326,656	4,706,760	390,063	9,635,678	34,059,157	157	54,051,315

Value of Unserved Energy	=	$2.50	/kwh (1993)
Estimated Battery Capital Cost	=	$140	/kWh(1993)
Battery Salvage Value	=	20%	
Battery Shelf Life(Years)	=	15	
Battery O&M	=	0.25%	
Estimated Battery Replacement Cost		$112	/kWh(1993)
Estimated PC+BOP Capital Cost		$200	/kW(1993)
(a) Generation Capital Deffered		$14,864,258	($1,997)
(b) Transmission Capital Deffered		$3,620,000	($1,997)
(c) Distribution Capital Deffered		$300,000	($1,997)
Estimated Battery Capital Cost		$36,228,715	($1,997)
Estimated PCS+BOP Capital Cost	=	$7,393,615	($1,997)
Estimated Battery Replacement Cost	=	$56,090,237	($2,012)
Estimated Battery 2nd Replacement Cost	=		
Equivalent 30 Year Life Cost	=	$192	/kWh(1993)
		$1,341	/kW(1993)
BENEFIT/COST RATIO		0.63	

TABLE F13

ESTIMATED VALUE OF BENEFITS AND BATTERY COSTS
FOR WARRENTON

ASSUMED BATTERY SIZE= 218,000 KWH ; 5 HOURS

YEAR	ANNUAL SAVINGS GENERATION	TRANSMISSION	DISTRIBUTION	BACK-UP/ RELIABILTY CREDIT	TOTAL SAVINGS	NET VALUE $/KWH	ANNUAL BATTERY COST
1997	1,790,563	220,032	0	2,443,709	4,454,304	20	5,058,984
1998	1,813,074	222,798	0	2,553,676	4,589,548	21	5,082,148
1999	1,836,598	225,689	0	2,668,591	4,730,879	22	5,106,353
2000	1,861,181	228,710	0	2,788,678	4,878,569	22	5,131,648
2001	1,886,870	231,867	0	2,914,169	5,032,905	23	5,158,081
2002	1,913,715	235,165	0	3,045,306	5,194,186	24	5,185,704
2003	1,941,768	238,613	0	3,182,345	5,362,725	25	5,214,569
2004	1,971,083	242,215	0	3,325,550	5,538,849	25	5,244,734
2005	2,001,718	245,980	0	3,475,200	5,722,897	26	5,276,256
2006	2,033,731	249,913	0	3,631,584	5,915,228	27	5,309,196
2007	2,067,184			3,795,006	5,862,190	27	5,343,619
2008	2,102,144			3,965,781	6,067,924	28	5,379,591
2009	2,138,676			4,144,241	6,282,917	29	5,417,182
2010	2,176,852			4,330,732	6,507,584	30	5,456,464
2011	2,216,746			4,525,615	6,742,361	31	5,497,513
2012	2,258,436			4,729,267	6,987,703	32	8,797,469
2013	2,302,001			4,942,084	7,244,085	33	8,835,323
2014	2,347,527			5,164,478	7,512,005	34	8,874,881
2015	2,395,101			5,396,880	7,791,981	36	8,916,219
2016	2,444,817			5,639,739	8,084,556	37	8,959,417
2017	2,496,769			5,893,528	8,390,297	38	9,004,559
2018	2,551,060			6,158,736	8,709,796	40	9,051,732
2019	2,607,793			6,435,879	9,043,672	41	9,101,028
2020	2,667,080			6,725,494	9,392,574	43	9,152,542
2021	2,729,034			7,028,141	9,757,175	45	9,206,375
2022	2,793,776			7,344,408	10,138,184	47	9,262,630
2023	2,861,432			7,674,906	10,536,338	48	9,321,416
2024	2,932,132			8,020,277	10,952,409	50	9,382,848
2025	3,006,014			8,381,189	11,387,203	52	9,447,045
2026	3,083,220			8,758,343	11,841,563	54	9,514,130
NET P.V. (1993 $)	19,415,719	1,263,723		36,397,107	57,076,550	262	57,167,755

Value of Unserved Energy	=	$9.40	/kwh (1993)
Estimated Battery Capital Cost	=	$140	/kWh(1993)
Battery Salvage Value	=	20%	
Battery Shelf Life(Years)	=	15	
Battery O&M	=	0.25%	
Estimated Battery Replacement Cost		$112	/kWh(1993)
Estimated PC+BOP Capital Cost		$200	/kW(1993)
(a) Generation Capital Deffered		$14,932,756	($1,997)
(b) Transmission Capital Deffered		$1,835,000	($1,997)
(c) Distribution Capital Deffered		$0	($1,997)
Estimated Battery Capital Cost		$36,395,668	($1,997)
Estimated PCS+BOP Capital Cost	=	$10,398,762	($1,997)
Estimated Battery Replacement Cost	=	$56,348,717	($2,012)
Estimated Battery 2nd Replacement Cost	=		
Equivalent 30 Year Life Cost	=	$202	/kWh(1993)
		$1,008	/kW(1993)
BENEFIT/COST RATIO		1.00	

TABLE F14

ESTIMATED VALUE OF BENEFITS AND BATTERY COSTS
FOR WARRENTON

ASSUMED BATTERY SIZE= 218,000 KWH ; 5 HOURS

YEAR	ANNUAL SAVINGS GENERATION	TRANSMISSION	DISTRIBUTION	BACK-UP/ RELIABILTY CREDIT	TOTAL SAVINGS	NET VALUE $/KWH	ANNUAL BATTERY COST
1997	1,790,563	220,032	0	678,519	2,689,114	12	5,058,984
1998	1,813,074	222,798	0	709,053	2,744,925	13	5,082,148
1999	1,836,598	225,689	0	740,960	2,803,247	13	5,106,353
2000	1,861,181	228,710	0	774,303	2,864,194	13	5,131,648
2001	1,886,870	231,867	0	809,147	2,927,883	13	5,158,081
2002	1,913,715	235,165	0	845,558	2,994,439	14	5,185,704
2003	1,941,768	238,613	0	883,609	3,063,989	14	5,214,569
2004	1,971,083	242,215	0	923,371	3,136,669	14	5,244,734
2005	2,001,718	245,980	0	964,923	3,212,620	15	5,276,256
2006	2,033,731	249,913	0	1,008,344	3,291,988	15	5,309,196
2007	2,067,184	254,024		1,053,720	3,374,928	15	5,343,619
2008	2,102,144	258,320		1,101,137	3,461,601	16	5,379,591
2009	2,138,676	262,809		1,150,688	3,552,173	16	5,417,182
2010	2,176,852	267,501		1,202,469	3,646,822	17	5,456,464
2011	2,216,746	272,403		1,256,580	3,745,730	17	5,497,513
2012	2,258,436	277,526		1,313,126	3,849,088	18	8,797,469
2013	2,302,001	282,880		1,372,217	3,957,098	18	8,835,323
2014	2,347,527	288,474		1,433,967	4,069,968	19	8,874,881
2015	2,395,101	294,320		1,498,495	4,187,917	19	8,916,219
2016	2,444,817	300,429		1,565,928	4,311,174	20	8,959,417
2017	2,496,769	306,814		1,636,394	4,439,977	20	9,004,559
2018	2,551,060	313,485		1,710,032	4,574,577	21	9,051,732
2019	2,607,793	320,457		1,786,984	4,715,233	22	9,101,028
2020	2,667,080	327,742		1,867,398	4,862,219	22	9,152,542
2021	2,729,034	335,355		1,951,431	5,015,820	23	9,206,375
2022	2,793,776	343,311		2,039,245	5,176,332	24	9,262,630
2023	2,861,432	351,625		2,131,011	5,344,068	25	9,321,416
2024	2,932,132	360,313		2,226,907	5,519,352	25	9,382,848
2025	3,006,014	369,392		2,327,117	5,702,523	26	9,447,045
2026	3,083,220	378,879		2,431,838	5,893,937	27	9,514,130
NET P.V. (1993 $)	19,415,719	2,385,885		10,106,005	31,907,610	146	57,167,755

Value of Unserved Energy	=	$2.61	/kwh (1993)
Estimated Battery Capital Cost	=	$140	/kWh(1993)
Battery Salvage Value	=	20%	
Battery Shelf Life(Years)	=	15	
Battery O&M	=	0.25%	
Estimated Battery Replacement Cost		$112	/kWh(1993)
Estimated PC+BOP Capital Cost		$200	/kW(1993)
(a) Generation Capital Deffered		$14,932,756	($1,997)
(b) Transmission Capital Deffered		$1,835,000	($1,997)
(c) Distribution Capital Deffered		$0	($1,997)
Estimated Battery Capital Cost		$36,395,668	($1,997)
Estimated PCS+BOP Capital Cost	=	$10,398,762	($1,997)
Estimated Battery Replacement Cost	=	$56,348,717	($2,012)
Estimated Battery 2nd Replacement Cost	=		
Equivalent 30 Year Life Cost	=	$202	/kWh(1993)
		$1,008	/kW(1993)
BENEFIT/COST RATIO		0.56	

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2504	L. Lachenmeyer
2522	K. Grothaus
2523	D. Doughty
2525	P. Butler (10)
2525	A. Akhil
2525	J. Braithwaite
2525	N. Clark
2525	J. Freese
2525	R. Jungst
2525	S. Klassen
3714	J. Kerr, Attn: D. Wilt
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